UTILIZATION OF COAL WASHERY TAILINGS

FLUIDIZED BED COMBUSTION TECHNOLOGY

APPLIED TO THE CO-GENERATION OF

COAL DRYING AND ELECTRICAL POWER

FINAL REPORT

A Co-operative study with
Luscar Ltd. and TransAlta Utilities Corporation

Work on this project was conducted under the auspices of the Canada Centre for
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EXECUTIVE SUMMARY

Lurgi Canada Ltd., under contract to Luscar Ltd., has developed a process and plant design which will utilize coal washery tailings as a fuel source for fluid bed combustion. The plant will produce hot flue gas for coal drying at Luscar's Coal Valley minesite and raise sufficient steam for the generation of 30 MW of electric power. TransAlta Utilities Corporation, who supply electric power to the Coal Valley Mine, have worked in conjunction with Luscar in this study. The study was developed in two phases:

I. Develop preliminary plant process designs and capital investment estimates for three power production scenarios (10 MW, 20 MW and 30 MW).

II. Select the most promising alternative and develop a detailed plant layout including major equipment specifications, capital and operating costs and availability estimates.

The study concludes that it is technically feasible to produce flue gas for drying 600 tons per hour of coal while simultaneously providing steam for a 30 MW turbine/generator. The process design allows for a demand reduction of one third in dryer duty while maintaining full electrical power output. The dryer and turbine can also operate independently should one function be shut down.

Total capital investment, including circulating fluid bed boiler, turbine/generator water treatment, materials handling and associated auxiliaries is estimated at 45 million Canadian dollars.

Direct operating costs have been estimated at 1.8 million Canadian dollars annually for labour and maintenance, with a station service requirement of 3.0 MW. Fuel consumption would be about 100 tons per hour.

The annual operating schedule is 6,200 hours for the coal dryer and 7,536 for power generation corresponding to an availability of 86%.

Luscar and TransAlta have examined the cost/benefit aspects of the proposed plant installation and have concluded that the project is not economically viable under the present circumstances that exist.

A number of major factors influence the economic feasibility of the project. These include:

1. The value of the fuel that would be displaced by the co-generation project. This includes fuel for the coal dryer and plant heating system as well as fuel presently burned to provide 30 MW of power on the existing electrical system.

2. The need for additional capacity and energy on the power system.

3. The capital and operating costs of the co-generation project.

However, the technology is certainly feasible and transferrable to other coal mine sites having similar requirements and more favourable opportunities for co-generation.

RÉSUMÉ ADMINISTRATIF

La société Lurgi Canada Ltd., sous contrat avec la société Luscar Ltd., a élaboré un procédé et une conception d'usine qui utilisent des résidus de lavage du charbon comme source de combustible pour la combustion par lit fluide. L'usine produirait du gaz chaûd d'echappement pour sécher le charbon à la mine de "Luscar Coal Valley". En outre, elle produirait suffisamment de vapeur pour produire 30 MW d'energie électrique. TransAlta Utilities Corporation, qui alimente la mine de "Coal Valley" en énergie électrique, a oeuvré dans le cadre de cette etude conjointment avec Luscar Ltd. L'étude comprenait deux etapes:

I. la conception prelimiaire de procédés d'usine et l'évaluation des investissements en capital requis pour trois méthodes de production d'énergie (10 MW, 20 MW, 30 MW).

II. le choix des solutions de rechange les plus prometteuses et l'élaboration d'un plan détaillé de l'usine, y compris des spécifications quant à l'équipement lourd, l'évaluation des coûts en capital et des coûts d'exploitation ainsi que des disponsibilitiés.

L'étude a permis de conclure qu'il est techniquement possible de produire suffisamment de gaz pour sécher 600 tonnes de charbon à l'heure tout en produisant suffisamment de vapeur pour faire fonctionner une turbogénératrice de 30 MW. Le procédé permittrait de réduire la demande de la puissance de séchage d'un tiers, tout en conservant un débit maximal d'énergie électrique. Le sécheur et la turbine peuvent également fonctionner de facon indépendante advenant qu'une de ces duex fonctions soit interrompue.

L'investissement en capital total, y compris la chaudière à lit de circulation fluide, le traitement de l'eau pour la turbogénératrice, la manutention des matériaux, et les procédés auxiliares, est évalue a 45 millions $ Canadiens.

Les coûts d'exploitation directs annuels ont été évalués a 1.8 million $ Canadiens pour la main-d'oeuvre et l'entretien, ce qui comprend également une consommation d'énergie de 30 MW à la station même. La consommation de combustible serait d'environ 100 tonnes à l'heure.

Le plan d'exploitation annuel serait de 6200 heures pour l'exploitation du sécheur à charbon, et de 7536 heures pour la production d'énergie, ce qui correspond à une disponibilité de 86 %.

Les sociétés Luscar et TransAlta Utilities ont examiné les aspects relatifs à la rentabilité d'une telle usine et ont conclu que le project n'est pas économiquement viable dans les conditions actuelles. Un certain nombre d'autres facteurs influencent la faisabilité économique du project, dont:

1. la valeur du combustible qui serait utilizé par le project de cogénération. Cela comprend le combustible pour le sécheur et le système de chaffage de l'usine ainsi que le combustible présentement brûlé pour fournir 30 MW d'énergie pour le systeme électrique actuel;

2. le besoin d'une plus grande capacité et d'une grande puissance pour le système électrique;

3. les coûts en capital et les coûts d'exploitation reliés au project de cogénération.

Cependant, il est possible de mettre au point cette technologie, qui pourrait être transférée à d'autres mines de charbon ayant des besoins semblables et présentant des possibilitiés de cogénération d'énergie plus favourables.

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1. INTRODUCTION

1.1 BACKGROUND

Luscar, Ltd. owns and operates a large bituminous coal mine at Coal Valley in west-central Alberta. Production requires beneficiation through a wet-washing plant, and as a consequence, the prepared coal must be dried prior to shipment. The present fluid bed dryer on site utilizes hot flue gas generated by firing clean coal in a conventional pulverized coal combustion chamber.

The beneficiation plant produces several reject coal materials which are presently being disposed on site. Luscar has previously examined the use of these tailings as a fuel source for coal drying (but with no power generation) through fluidized bed combustion. This investigation indicated that the cost savings due to fuel substitution could not support the investment cost for the fluidized bed combustion plant.

The purpose of the present study is to determine the technical and economic viability of a Lurgi circulating fluid bed plant:

1. To provide hot air/gas for coal drying, and, in addition,

2. To generate steam to provide turbine electric power.

The circulating fluid bed plant is to utilize one or more of the waste materials being rejected from the beneficiation plant as fuel.

TransAlta Utilities Corporation supplies the mine's power at Coal Valley and is participating with Luscar in examining the above cogeneration approach.

Lurgi was commissioned by Luscar, Ltd. to conduct this study in a phased approach:

Phase I - Develop process schemes, preliminary plant designs, budgetary investment estimates and operating requirements for three scenarios corresponding to different power production levels; select preferred option in consultation with Luscar and TransAlta.

Phase II - Develop preferred option in further detail, producing refined estimates of investment cost and operating requirements.

Circulating fluid bed combustion plants built in North America are offered jointly by Lurgi and Combustion Engineering as a consortium. Combustion Engineering has actively participated in this study and has developed the design of the water/steam/turbine circuits.

This report summarizes the results of both phases of the study.

1.2 SCOPE OF STUDY

The scope of study, as broken down for the two phases, is given below:

Phase I

- Establish concepts, process flowsheets, heat and material balances, and preliminary plant designs for three alternatives corresponding to different cogeneration levels,

  I - 10 MW electric power
  II - 20 MW electric power
  III - 30 MW electric power

  In each case sufficient hot air/gas should be generated to dry 600 stph product coal in the existing fluid bed drying plant.

- Develop relative investment cost estimates for the three alternatives.

- Develop operating requirements and characteristics for the three alternatives.

- Select preferred alternative in consultation with Luscar and TransAlta.

Phase II

- Expand design for selected option, developing major equipment list and duty specifications, order of magnitude materials requirements, conceptual plant layout, capital cost estimates, operating requirements, and availability assessment.

- Prepare study report summarizing the results of the entire study.

2. DESIGN BASIS

2.1 PLANT SITE AND BATTERY LIMITS CRITERIA

2.1.1 Plant Site

Coal Valley mine site, Alberta, Canada. Altitude, 4,600 ft. Ambient temperature range, -40 to 85 degrees F. Snow fall, 72 inches per year. Wind load, 100 mph.

Tentative location for the CFB/turbine facility: Area directly north of present dryer plant. This will require relocation of the two existing propane storage tanks.

2.1.2 Battery Limits

Solid fuels: Provide feed belt conveyor to intersect reject drop points on existing reject conveyor in washery building. This requires a new belt conveyor extending approximately 1/2 the length of the washery building. Provision is to be made for a 30-hour covered storage of fuel (bunker or silo) and a 14-day stock pile of fuel on an open pad. The latter is for use during period when the drying and washery plants are shut down, but power generation is to continue.

Limestone: Not required due to low sulfur content of fuel.

Ash Handling: Provide means to transport ash back to existing reject belt. Ash will be disposed in the same manner as rejects are presently being disposed. The ash must be cooled to approximately 200 degrees F.

Electric Power: Battery limits will be at the generator outlet (13.8 kV); TransAlta will establish costs for substation re-work and interconnect.

Water Make-up: Water make-up for the cooling tower and for boiler feed water will be pumped from the pond adjacent to pit 27E (15 ft. elevation to boiler plant).

2.2 FUEL

Four reject coal streams are available from the wash plant. The principal fuel to be used is the heavy media cyclone underflow. This material contains approximately 18% H_2O and 62% ash (dry basis), and has a high heating value of about 3,000 Btu/lb. This material (dry basis) is presently limited to about 90 stph, but in the future is expected to be available at rates up to 140 stph.

The above material is supplemented by spiral classifier reject. This material contains about 40% H_2O and 45% ash (dry basis), and has a high heating value of about 3,200 Btu/lb; it is currently available at a rate of about 17 stph.

A composite waste fuel feed, composed from the above two streams and with the analysis given in Table 2.1 was used as a basis of design. Particle size distributions of the two component feed materials are given in Table 2.2.

2.3 ENERGY PRODUCTION

2.3.1 Electric Power

- Alternative I - 10 MW (for on-site use)
- Alternative II - 20 MW (site use plus transfer to grid)
- Alternative III - 30 MW (site use plus transfer to existing grid transmission capacity)

Steam is to be generated at 900 degrees F/1200 psig. The generator is base loaded; steam generation must be constant regardless of dryer load.

2.3.2 Hot Air/Gas

Hot air or combustion gas in sufficient quantity to operate coal dryer at 600 stph coal. Total coal moisture inlet to dryer is 15%, total coal moisture outlet from dryer is 9%. Temperature at outlet of dryer is 160 degrees F. Turn down on hot gas for drying should be 1/3.

2.3.3 Steam generation is to continue when the dryer is shut down.

2.3.4 Drying is to continue when the turbine is shut down.

2.3.5 Plant Building Heat Distribution

A central heat distribution system is to be considered to provide heat for the various Coal Valley plant buildings. Extraction steam from the turbine would be required to supply approximately 50 million Btu/hr for this purpose. If practical, such a system would displace the present system of propane-fired space heaters at the various work stations and the propane-fired glycol heating circuit in the administration building.

Table 2.1

Composite Waste fuel Feed
for CFB Boiler Facility (as fired)

Carbon	21.3%
Hydrogen	1.8%
Sulphur	0.1%
Oxygen	8.0%
Nitrogen	0.5%
Ash	45.8%
Moisture	22.5%
HHV as Fired	7071 KJ/kg (3040 Btu/lb)
LHV as Fired	6125 KJ/Kg (2633 Btu/lb)

Table 2.2

Particle Size Distributions
of Waste Fuels

Stream Name: Heavy Media Cyclone Reject

Size	WT%
+ 1/2"	3.0
1/2" x 1/4"	20.2
1/4" x 1/8"	28.4
1/8" x 16 Mesh	16.9
16 Mesh x 28 Mesh	9.5
-28 Mesh	22.0

Stream Name: Spiral Classifier Coarse Fraction

Size	WT%
28 Mesh x 100 Mesh	100

2.4 EMISSIONS CRITERIA

Allowable SO_2 emission is 0.6 lb SO_2 per million Btu fired. No SO_2 removal is required providing that emissions are below this limit. Particulate emissions should be considered at 0.03 grains/scf.

2.5 CRITERIA RELATED TO EXISTING DRYER

(See also 3.3.2).

2.5.1 Pressure under deck (grate) of existing fluid bed dryer, -1.5 in. W.G.

2.5.2 Variations in coal rate or moisture content are accommodated by varying inlet (combustion) air temperature. Total outlet gas flow rate at 160 degrees F is maintained constant in order to retain gas velocity in dryer. Turn down to 1/3 of coal rate is required.

2.5.3 Variations in coal size occur due to conditions in coal washery. Gas velocity in the dryer is adjusted in order to accommodate these variations.

2.5.4 Oxygen content in dryer gas is not an operating or design criteria.

2.5.5 Waste gas cleaning system in dryer plant consists of:

- Four parallel cyclones,
- ID fan,
- Two parallel venturi scrubbers, and a common separator/demister tower directly coupled to a stack.

The ID fan is sized for 235,000 acfm at 150 degrees F (equivalent to 710,000 lb/h), and imparts a differential pressure of 55 inches W.G. Pressure drop from ID fan outlet to stack is 32 inches W.G. Solids emissions limit of 0.03 gr/scf is being met.

The present waste gas cleaning system (with the dryer operating at a coal through-put of 500 to 600 stph coal) collects approximately 40 stph dust in the cyclones; scrubber effluent is about 200 gpm at 5% solids.

Dryer plant shuts down for a 2 to 3 week period during the summer and for a 1 to 2 week period during the winter. It also shuts down every Wednesday for general maintenance. Total annual operating hours are approximately 6,200.

3. FLUIDIZED BED COMBUSTION

3.1 TYPES OF FLUID BED SYSTEMS

A fluidized bed is a system in which a gas, distributed by a distributor plate or grid, is blown through solids creating a "fluidized state". A sufficient gas velocity is employed to create a vigorous, well-mixed system which behaves much like a boiling fluid. Due to the excellent gas/solid mixing, high heat and mass transfer rates are achieved in a fluidized bed.

The fluid bed system operates in a range between stoker or grate firing and pulverized fuel firing systems (see Figure 1).

In stoker-fired systems, low air velocities are employed and "lump" sized coal can be burned. The fuel is fed by a stoker and grate and remains stationary on the grate as it burns.

The stationary or bubbling fluidized bed is characterized by fluidizing air velocities which are sufficiently low to maintain a well-defined bed with high solids density. The fluidizing velocity (3-7 feet per second) and particle size (typically below 1/2 inch) are generally selected to minimize solids from leaving the bed.

The circulating fluid bed (CFB) operates with finer particle size (typically less than one millimeter) and greater fluidizing velocity (generally 20 to 25 feet per second). This, combined with more intensive gas/solids mixing, produce high heat and mass transfer rates and eliminates the formation of large bubbles within the fluidized mass.

The CFB also differs from the bubbling bed by the fact that the solids are entrained and discharged from the combustion zone along with the flue gas. The solids are subsequently separated from the flue gas by a high-efficiency cyclone, and are recycled back to the combustor.

The pulverized fuel system operates with very high gas velocities (greater than 30 feet per second) and very fine particles (less than 90 microns). This system may be characterized as a transport reactor in which gas and solids are conveyed concurrently. Short residence time is also characteristic for this system.

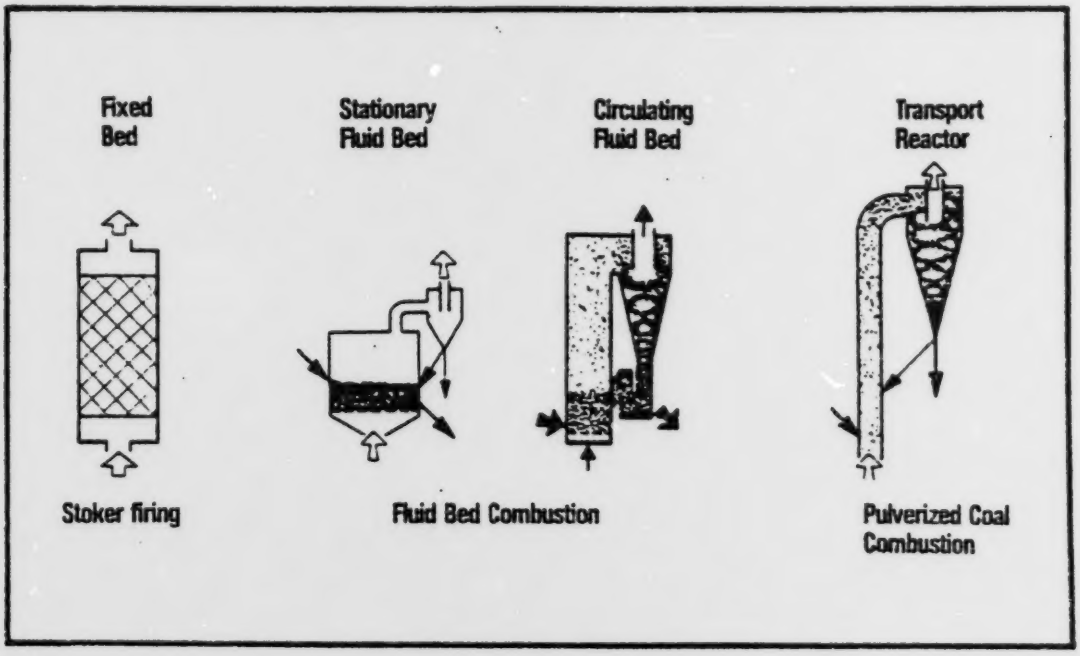

Figure 1. Types of Fluid Bed Systems

Stoker and pulverized fuel fired systems typically operate at temperatures greater than 1800°F. these high temperatures enhance nitrogen oxide formation from fuel-bound nitrogen as well as from nitrogen in the air. In addition, flue gas desulfurization, if required, must be achieved in a separate unit.

Fluidized bed systems are able to remove sulfur dioxide directly in the combustor. This is accomplished through the addition of limestone to the fluid bed. The limestone calcines to form calcium oxide (CaO) and then reacts with the SO_2 to form calcium sulfate.

The ideal temperature range for desulfurization in a fluidized bed is 1550 to 1600°F. Fluidized bed combustors are therefore normally operated in this temperature range.

The Lurgi circulating fluid bed system (see Figure 2) is a patented and proprietary process generally consisting of the following components:

- Coal (and if required, limestone) preparation and feeding;
- CFB combustor with or without heat transfer surface (i.e., water walls);
- Recycling cyclone;
- Fluid bed heat exchanger (if required);
- Convective heat transfer section;
- Flue gas cleanup system, i.e., baghouse or precipitator;
- Induced draft fan and stack;
- Air blowers;
- Steam turbine and generator (for plants which generate electricity).

Combustion temperature is normally controlled in the range of 1500 to 1600 °F. Due to the high gas velocity, the fine solids (hot ash) are entrained. As the solids exit the combustor, they are captured by the recycling cyclone.

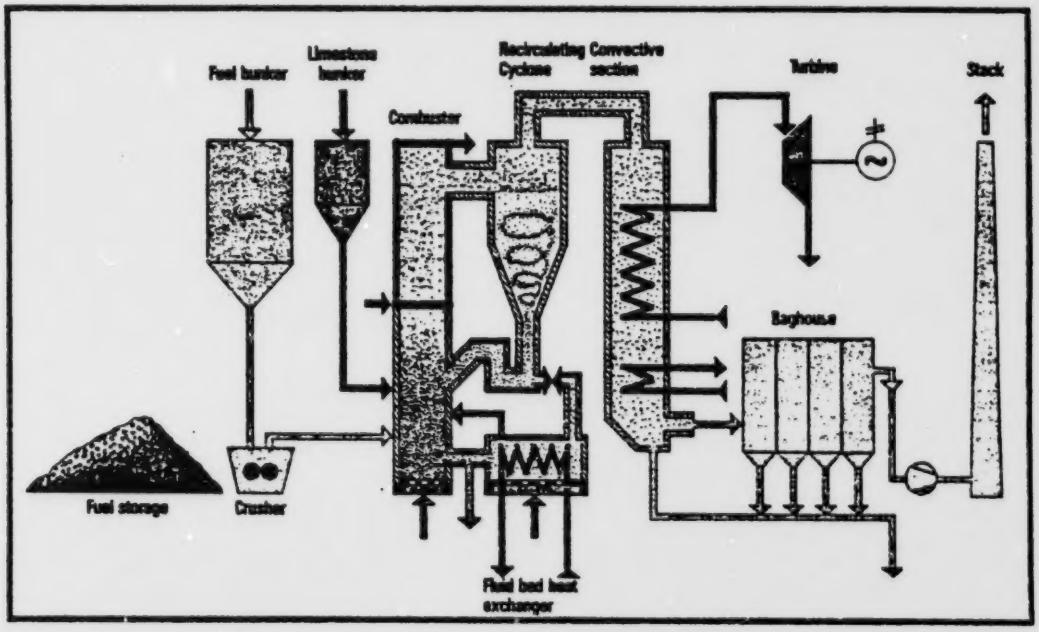

Figure 2. Circulating Fluid Bed Process

Entrained solids are recycled back to the combustor. In plants provided with an external heat exchanger, part of the solids flow is diverted through the heat exchanger (FBHE). Here, heat is imparted from the solids to immersed tube bundles (the fluid bed heat exchanger is a low velocity, bubbling fluidized bed with immersed heat transfer surface). The solids then exit the fluid bed heat exchanger, and are returned to the combustor. Typically, the immersed bundles are designed for steam superheat and/or evaporative service.

Hot flue gas leaving the recycling cyclone passes through a convective section where additional heat is removed. The convective pass may have heat transfer surface for superheat, economizing, or combustion air pre-heat, depending on specific needs for each application. The flue gas is finally dedusted (fly-ash removal) in a baghouse or electrostatic precipitator.

Combustion air is fed to the combustor as primary air (fed through the distributor plate at the bottom of the combustor) and as secondary air (fed partway up the combustor). This "staging" of the combustion further suppresses NO_x formation. Coal (and limestone, if required) are fed to the bottom of the combustor.

Crushing the coal or other fuels to a top size of 1/4 to 1/2 inch is generally sufficient to provide good CFB performance. This is due to the fact that, as the coal burns, the particle size of the remaining ash becomes less than the original size of the coal.

The coal distribution and feeding system for a CFB is very simple as only one or two feed points are generally required. The simplification of the fuel feeding system relative to other fluidized bed systems is due to the enhanced mixing characteristics of a circulating fluid bed.

When required, fine limestone (top size of about 1 millimeter) is utilized in the CFB for efficient SO_2 removal. The use of the fine-grained material provides increased specific surface for improved sulfation, that is, formation of gypsum.

3.3 ADVANTAGES OF THE CIRCULATING FLUID BED

The circulating fluid bed combustor offers unique advantages as a steam generator or a producer of other types of thermal energy:

- the system can burn a variety of fuels efficiently, including coals with high sulfur and high ash contents, washery rejects, lignite, peat, wood, bark, petroleum coke and other refinery residues. Typically, many of these fuels are difficult and/or uneconomical to burn in conventional systems. The CFB also has sufficient flexibility to burn different types of fuels in the same combustor.

- High carbon burn-out (over 99%) can be achieved for all fuels including those with low heating values and/or low proportion of volatiles.

- A high degree of desulfurization can be achieved directly in the combustor. Over 90% SO_2 removal can be obtained with a calcium-to-sulfur (Ca/S) molar ratio of 1.5.

- Low NO_x emissions (less than 200 volumetric parts per million) can be obtained through "staging" the combustion air.

- The high carbon burn-out (combustion efficiency) and the low limestone consumption also contribute to high overall thermal efficiencies.

- Fuel preparation and feeding is simple. Crushing is sufficient for the preparation of most of the fuels, and generally only one or two fuel points are required.

4. PHASE I: EVALUATION OF OPTIONS

4.1 DEVELOPMENT OF OPTIONS

4.1.1 General

The objective of this phase of the study was to develop process concepts for three alternatives corresponding to the generation of 10 MW, 20 MW and 30 MW, respectively. Preliminary cost estimates were to be developed for the three alternatives, and the most attractive alternative was to be identified for further development. Plant building heat distribution considerations were deferred to Phase II.

4.1.2 Requirements for Existing Coal Drying Plant

A goal for all alternatives was to try to utilize directly the flue gas from the CFB boiler plant as the drying gas medium in the existing dryer plant. This would avoid the need to transfer heat through a metallic surface (such as would be required in heating air for use as drying medium), and would permit the use of the existing gas clean-up train in the dryer plant for cleaning up the CFB flue gas. Heat and mass balance calculations confirmed CFB flue gas could indeed be used directly in this manner.

The gas clean-up system in the existing coal drying plant consists of a bank of cyclones, an I.D. fan, and a venturi scrubber. In order to accommodate this existing equipment, the gas flow and temperature entering the induced draft fan should be maintained at or near 322,000 Kg/h and 71°C (710,000 Lb/h and 160°F).

The flow of flue gas is held constant as the dryer load varies in order to provide proper fluidization velocity. The temperature of the flue gas entering the dryer, however, must decrease as the dryer load decreases.

In the concepts developed, gas flow is controlled by the addition of dilution air to the flue gas. The dilution air is injected within the boiler island to promote good mixing.

Temperature is controlled by removing heat from the flue gas in the air preheater of the CFB boiler. The flow of the flue gas and its heat content are approximately proportional to the total process duty for steam production and for coal drying. As the dryer duty decreases, the flue gas flow from the CFB boiler will also decrease. But the percent change in dryer load is greater than the percent change in flue gas flow and heat content. As the dryer is turned down, therefore, the air preheater duty in the CFB boiler increases.

4.1.3 Additional Process Requirements

The plant design concepts were based on the following considerations:

(a) The generator is base-loaded. Steam generation should not fluctuate with dryer load.

(b) Steam generation continues when the dryer is shut down. To accomplish this, a bypass duct will be installed around the dryer. This bypass will contain spray nozzles to cool the flue gas stream which then enters the existing gas cleanup equipment and I.D. fan.

(c) Coal drying continues when the turbine is shut down. The methods for accomplishing this are different for the three alternates, and are discussed in later sections of the report.

(d) Oxygen content of the gas at the dryer is not a consideration.

(e) The combustor operates with 20% excess air.

(f) There is no need to inject limestone into the combustor for sulphur dioxide removal due to the low sulfur content of the fuel and relatively high CaO content in the ash component of the fuel.

4.1.4 Concept Development

Conceptual process flow diagrams were prepared for the 10 MW, 20 MW, and 30 MW alternatives. Separate flowsheets (see enclosed drawings) were made for the combustor, showing the air and flue gas flow schemes and for steam generation, showing the flow schemes for steam and water.

Material and heat balances were also developed for the three alternatives, corresponding to both full dryer load and one-third dryer load operation (600 tph and 200 tph coal feed).

The design philosophy throughout was to decouple the steam production and coal drying as much as possible. All the evaporative surface was therefore placed in external fluid bed heat exchangers. (In ordinary CFB plants, where all the heat is used for steam generation, evaporative waterwalls are normally installed in the combustor).

In general, the quantity of heat delivered by means of the hot flue gas to the coal dryer is controlled by varying the amount of heat extracted from the flue gas in the convective pass of the boiler. Absolute gas flow rate, on the other hand, is controlled by varying the quantity of dilution air added to the flue gas.

Under conditions of low dryer load (or dryer not operating at all), sufficient heat cannot be removed from the flue gas in the convective pass of the boiler. In such cases part (or all) of the CFB flue gas by-passes the dryer and is quenched by means of an in-line water spray system. Final clean-up of the cooled gas is again accomplished in the cyclone/scrubber train of the existing dryer plant.

Brief concept descriptions for the three alternatives are given in the following sections. A more detailed process/plant description for the selected alternative is provided in Section 5.1.

4.1.5 Alternative I (10MW)

All the steam generating surface in this alternative is provided in the external fluid bed heat exchanger. A steady production rate of steam is maintained by controlling the circulation rate of solids through the exchanger. The convective pass consists only of an air preheater. Dilution air is injected at both the inlet and the outlet of the convective pass. The fluegas temperature at the inlet to the air preheater is controlled by dilution of the flue gas. The total flow of dilution air is controlled by dryer requirements. The temperature of the gas entering the dryer is controlled by bypassing primary and secondary air around the air preheater.

At the lowest dryer load, the air preheater can not remove sufficient heat from the flue gas and part of the flue gas is diverted through the dryer bypass line where it is cooled by the water spray.

When steam production is to be shut down, the solids circulation through fluid bed heat exchanger is stopped and combustion rate in the CFB combustor is controlled only by the requirements of the dryer.

4.1.6 Alternative II (20MW)

It would always be necessary to quench part of the fluegas if this alternative had the same scheme as the 10 MW plant. The heat that would be thus thrown away would come from burning valueless fuel, but such heat is not gratis. The economizer has therefore been placed in the back pass in this alternate. This minimizes fuel consumption and, hence, equipment size and power requirement for the combustion air fans.

As in the 10 MW alternative, dilution air is injected both at the inlet and at the outlet of the convective pass. The flow is distributed to keep the temperature of combustor flue gas entering the air preheater section within reasonable limits. At full dryer load, nearly all the dilution air enters the inlet of the convective pass, and at 1/3 dryer load it enters at the convective pass outlet.

When steam production is to be shut down, the solids flow through the fluid bed exchanger is stopped. The reduction in process heat requirements will lead to a decreased flow rate of fluegas and an increase in the need for dilution air. Dilution air (and bypass secondary air) will be added at the backpass inlet and will cool the fluegas sufficiently so that the economizer can run empty without overheating.

4.1.7 Alternative III (30 MW)

This is similar to the 20 MW alternative. Part of the superheat surface, as well as all of the economizer surface, is located in the convective pass. When steam production is shut down, a portion of cooling secondary air is injected at the convective pass inlet so that the superheater and the economizer can run empty without overheating.

The 30 MW alternative plant could not meet the criterion of gas flow to the induced draft fan. The flow at full load is about 16% above the indicated gas flow rate. (The existing fan at present, however, exceeds the calculated flowrate for this alternative; Luscar is planning to de-rate the fan to the indicated 710,000 lb/hr flowrate due to current production requirements. Assuming that the CFB project will be implemented, the planned fan de-rating should not be carried out).

A small flow of dilution air is needed at 1/3 dryer load to supplement the flue gas flow and this is provided from the secondary air fan. A dedicated dilution air fan would operate intermittently and would not produce a significant savings in power requirements.

Note that in this alternative one of the functions of the steam surface in the backpass is to shield the air preheater from high flue gas temperature. This purpose is served by dilution air in the smaller plants.

4.1.8 Turbine/Generator and Auxiliary Systems

The following facilities are included in all three alternatives:

(a) Turbine/generator.

(b) Surface condenser, operating in conjunction with the steam turbine.

(c) Cooling Water Tower. (The use of pond water as cooling water, with heat dissipation by means of evaporative and convective pond cooling was examined and determined to be inadequate at Coal Valley).

(d) Boiler Feed Water Treatment Plant, consisting of a demineralizer plant and polishing plant.

(e) Raw Water Supply System by pipeline from the pond water source to boiler plant.

(f) Switchgear Upgrading. Requirements were estimated by TransAlta.

4.2 RELATIVE CAPITAL COST ESTIMATES

Preliminary investment cost estimates (Table 4.1) were made for the three alternatives during Phase I of the study. These estimates were mainly pro-rated from existing in-house data on other projects and are subject to the several limitations:

- Fuel feed storage and reclaim facilities excluded;
- Building heat distribution system (for possible replacement of existing propane-based space heaters) excluded;
- Construction cost estimates specific to Coal Valley were not made (used generalized historical data);
- Costs for up-grading gas cleaning train in existing coal drying plant were not estimated.

It should be noted that the above limitations were to be considered during Phase II of the study.

The estimates, in addition, excluded:

- Taxes
- Escalation
- Construction camp facilities and operating costs
- Travel and subsistence for construction workers.

The cost estimates indicate relatively favorable investment costs despite the limitations noted above. As expected, due to the economy of scale, the 30 MW alternate shows the lowest investment cost per kilowatt produced.

Fuel consumption and station service power consumption data are given in Table 4.2.

Table 4.1

TOTAL INSTALLED COST SUMMARY (CANADIAN $ MILLION)

	ALT I 10 MW	ALT II 20 MW	ALT III 30 MW
1. Boiler Island, Incl. Feed Handling	13.1	15.7	18.0
2. Turbine/Generator & Surface Condenser	4.7	7.4	9.6
3. Cooling Tower	0.7	1.2	1.7
4. Water Supply & Treatment	0.6	0.8	1.1
5. Switchgear Upgrading*	0.3	0.3	0.8
Total Installed Cost	19.4	25.4	31.2

* Costs provided by TransAlta.

Table 4.2

ESTIMATED CONSUMPTION FIGURES*

	ALT I 10 MW	ALT II 20 MW	ALT III 30 MW
Fuel, as fired, stph	53	71	101
Station service power, MW	1.6	2.0	2.5

* Corresponding to indicated turbine power production and drying load of 600 stph coal. Power consumption for drying plant including ID fan is excluded from these figures.

4.3 SELECTION OF PREFERRED OPTION

The results from Phase I were reviewed with Luscar and TransAlta at a review meeting on November 20, 1984. Based on the work accomplished to that date the following conclusions were reached:

- Coal drying with co-generation of electric power via a CFB combustor is technically feasible;
- The existing gas cleaning train in the coal drying plant can be used to clean the CFB flue gas, thereby avoiding the need for a separate gas cleaning system. Some modifications in the existing plant will be needed to upgrade the plant (to be defined in Phase II);
- The 30 MW alternative has the most favorable economics due to the effect of scale of operation on investment cost;
- The 30 MW option also appears to be the most acceptable alternate technically in-as-much as the backpass includes superheater and economizer surface and is therefore closer to conventional configuration and design;
- From a plant availability point of view, all three alternatives would be expected to have similar on-line stream factors.

Based on the above conclusions it was mutually agreed that the 30 MW alternative should be pursued in further detail in Phase II.

5. PHASE II: 30 MW OPTION

5.1 PROCESS/PLANT DESIGN

5.1.1 Fuel Feed

The washery produces four waste streams, two of which were selected to supply fuel to the CFB. These two alone will be available in sufficient quantity for operation of the cogeneration plant. The four waste streams are the Wemco rejects, heavy media cyclone rejects, spiral classifier coarse fraction, and thickener filter cake.

The Wemco rejects are produced at the rate of 97 short ton per hour (stph). This material contains 60-65% ash (dry basis) and 18% moisture. The size is plus 1/2 inch minus 4 inch, and the heating value is 2800 Btu/lb, as received. This material was rejected for use in the CFB because of the need for significant size reduction.

The heavy media cyclones rejects are produced at the rate of 91 stph. The production will eventually go up to 140 stph. This material is minus 1/2 inch plus 28 mesh, with 55-62% ash (dry basis), 18% moisture, and a heating value of 3000 Btu/lb as fired. This material is acceptable fuel for the CFB combustor.

The spiral classifier coarse fraction is produced at a rate of 17 stph. The material is minus 28 mesh plus 100 mesh, with 45 to 55% ash (dry basis) and 40% moisture. The heating value is 3200 Btu/lb. This material by itself is not very free-flowing because of the high surface moisture. This stream, when mixed with the heavy media cyclone rejects, is acceptable fuel for the CFB.

The fourth stream is filter cake recovered from the thickener underflow. This material is minus 100 mesh with 45% water, 45% ash (dry basis), and a heating value of 3800 Btu/lb. It is undesirable for use as fuel because of its poor material handling characteristics.

The two chosen fuels, heavy media cyclone rejects and spiral classifier coarse fraction, are produced at the west end of the washery building. These will be delivered to a belt conveyor parallel to the existing rejects conveyor. The ash will be collected from two fluidized ash coolers within the boiler island and will be continuously delivered to the existing rejects belt in the washery building.

5.1.2 Materials Handling

There are two fuel storage facilities, the 30-hour storage and the 14-day storage. The 30-hour storage is an above-ground bunker. Fuel is delivered by conveyor M-121 at the rate of 157 stph from the washery, or is re-claimed at the rate of up to 400 stph from the 14-day pile. When the 30-hour bunker is filled to capacity, the fuel from the washery is diverted either to the 14-day pile or the existing rejects belt.

The fuel is fed from the 30-hour bunker to the 2-hour surge bin inside the boiler island. This transfer is intermittent, via Conveyor M-126. M-126 will operate 22 hours per day at a rate of 110 stph when the dryer plant is at full load, and 18 hours per day when the dryer plant is at one-third load.

The 14-day pile is intended to supply fuel to the cogeneration plant when the coal plant is down for its annual turnaround. When the coal plant is at full capacity, 1344 tons per day will be delivered by Conveyor M-123 to the outdoor conical pile. The 14-day pile proper is stacked by mobile equipment. It will take three to four weeks to form the 14-day pile. The area plan does permit the use of a radial stacker, if this option should be preferred by Luscar.

The 14-day pile is reclaimed by mobile equipment to the 30-hour bunker via a hopper and frozen coal crusher, and conveyors M-125 and M-121. The equipment (G-101, M-125, M-121) is sized so that a day's supply of coal can be reclaimed from the 14-day pile in one shift.

The 14-day pile will be reclaimed when the washery is shut down for more than 24 hours or when the coal plant is operated at low throughput for more than three consecutive days.

All conveyors are in enclosed galleries with two walkways; maximum conveying angle is 16 degrees.

5.1.3 Boiler Island

The CFB boiler island performs two functions simultaneously and independently. It supplies hot flue gas to the coal dryer at approximately constant flow and it supplies a constant flow of steam to the turbine. The turbine is base-loaded. The dryer demand can vary from zero to a throughput of 600 stph of coal. The flow of gas at the dryer exit is held as nearly constant as possible over the entire operating range to ensure good fluidization in the dryer.

Based on the presently planned de-rating of the existing ID fan, the gas flow target is 235,000 acfm at 150°F. This corresponds to 710,000 lb/hr of gas. Calculations for the present study show that at full load (600 stph coal) the dryer offgas flow will be 825,000 lb/hr, or sixteen percent above the flow rate given in the flowsheet provided by Luscar. Since the present Luscar flowsheet represents a planned downgrading of the plant, the ID Fan should be able to handle the higher calculated flow.

When the dryer is at one-third load, excess heat is removed from the fluegas of the CFB combustor in the air preheaters. This saves fuel and reduces the quantity of flue gas. The correct flow is made up by injecting secondary air into the flue gas stream at the convective pass exit. When the dryer is shut down, the convective pass will see the same conditions as when the dryer is at one-third load. The flue gas leaving the boiler island will be cooled to 160°F by water spray and will bypass the dryer vessel. The flue gas will go directly to the existing cyclones.

The unit will supply hot flue gas to the dryer when steam is not being generated. Under these conditions it is necessary to protect the empty steam-generation heat exchangers from exposure to high temperature. The combustor/hot cyclone/seal pot loop is nearly adiabatic since heat removal inside the Fluid Bed Heat Exchanger (FBHE) is stopped. Combustor temperature is held at 1600°F by injecting a relatively large amount of excess air. The temperature in the backpass is controlled by injecting cooling dilution air at the hot cyclone exit. This operating condition determines the maximum throughput of the primary and secondary air fans. There is no air supply from the FBHE Fluidizing Blowers, and the amount of carbon dioxide and water evolved in the combustion process is greatly reduced. The primary and secondary air fans make up the difference.

The dew point in the coal dryer offgas has been calculated to be as follows:

Mode of Operation	Dew Point °F
Full steam and dryer load	145
Full steam and 1/3 dryer load	132

This table indicates that the dew point of the offgas is always below 160°F, the operating dryer offgas temperature. Thus, there is always residual drying capacity left in the dryer offgas.

On the other hand, the driving force for drying (water saturation pressure minus partial pressure of water in gas stream) is lower in the proposed configuration than is the case in the present dryer operation. If the available driving force is insufficient to dry the coal to the required degree, a small compensating temperature increase in the dryer offgas (such as from 160°F to 170°F) may be necessary. The present hardware (dryer, ID fan, etc.) will be able to accommodate such minor changes.

5.1.4 Steam Generation

The steam circuit is conventional. It consists of makeup water treatment, condensate recycle, heating, expansion, and condensation. The steam conditions at the boiler island exit were set at 1200 psig and 900°F. These are typical steam conditions for a small generating station and form a valid basis for study purposes. Optimization of the steam conditions is outside the scope of this study.

The purpose of water treatment is to remove dissolved solids which can otherwise precipitate from solution in the evaporator and coat the tube surface with an insulating layer of scale. The fresh makeup water passes through cation beds, a de-gasifier, anion beds, and mixed-bed polishers. Recycled condensate is cleaned up in mixed-bed polishers.

The recycled condensate and the demineralized fresh water are contacted with steam in the deaerator to remove dissolved gases. The boiler feedwater is pumped to the boiler island, where the liquid is heated in the economizer to nearly saturation temperature. The hot water flows to the steam drum. The steam drum contents circulate through the evaporation surface in the Fluid Bed Heat Exchanger, and the returning mixture of vapor and liquid is separated in the steam drum. A small liquid blowdown stream is removed from the steam drum and discarded to purge the dissolved solids from the system. The steam passes through the low temperature superheater in the convective pass, a desuperheat station (where boiler feedwater is injected to control the temperature of the steam leaving the boiler island), the high temperature superheater in the convective pass, the FBHE superheater, and out to the turbine.

The turbine accepts steam at 1200 psig and 900°F and recovers energy as the steam is allowed to expand. The pressure and temperature at the turbine exit must be as low as possible to get the maximum amount of energy from the steam. The design conditions are two inches of mercury absolute pressure (well below atmospheric pressure) and 101°F. The fluid at the turbine exit consists of water vapor with a small amount of condensate.

The Condenser is mounted close to the turbine outlet. The steam is condensed and pumped back to the water treatment plant.

The cooling water system is conventional. The cooling water is warmed in the condenser and returned to the cooling tower where it is contacted with ambient air. The water is cooled by evaporation and pumped back to the condenser (and other water-cooled equipment). Fresh water makeup is supplied to the cooling tower, and a small amount of water is purged to prevent buildup of solids.

5.1.5 Plant Controls

For successful, steady operation, these process variables must be controlled: combustion air flow and distribution, combustor temperature, steam flow, steam temperature, flue gas flow, temperature of gas at the coal dryer exit, and ash inventory. These additional variables are measured to provide control: fuel flow, fluegas composition (oxides of nitrogen, carbon monoxide), and solids inventory.

The combustion air comes from six sources (C-501 through C-506). The flow from each source is measured and totaled. Primary air, which is injected at the bottom of the combustor, is supplied from C-501 only. Secondary air, which is injected in the lower part of the combustor, is supplied from the other five sources. Dual injection creates an oxygen-starved zone in the bottom of the combustor where most of the combustion process takes place. This has been shown to greatly reduce the formation of oxides of nitrogen.

The temperature of the dryer gas outlet is controlled at the air preheaters in the convective pass. A quantity of the cold combustion air is allowed to bypass the preheater. On increasing dryer demand, the bypass flow increases, causing a decrease in air preheater duty. This results in a higher temperature at the dryer inlet and a steady temperature at the dryer outlet.

The design point of the plant is at one-third dryer load. At this condition, the bypasses around the air preheaters are completely closed. If the dryer demand decreases below this point, additional heat is removed from the fluegas by means of the quench water spray.

The ash inventory in the fluidized combustor vessel is held constant by the automatic control valve M-302 in the duct D-362 at the solids outlet of E-360 (the North FBHE). This valve is a true automatic control valve, capable of maintaining any desired flow rate.

The total combustion air demand is proportional to the fuel flow. The flow of fuel is measured and controlled by the gravimetric feeder, and the total air flow demand is adjusted according to the fuel flow.

The design combustion air distribution is 40% primary and 60% secondary air. This is not difficult to control. The four blowers (C-503, C-504, C-505, C-506) operate at a constant rate, so that outputs of C-501 and C-502 are adjusted to give the desired air flow and distribution.

Flue gas flow rate is 752,600 lb/hr when the power and coal drying plants are at full load; this is sufficient gas for the dryer, and no dilution air is introduced into the flue gas stream. When dryer load is reduced to one-third capacity, the gas flow from the boiler convective pass is below that needed in the drying plant; a small amount of dilution air from C-502 is then injected into duct D-801 to make up the difference.

The combustor temperature is controlled by varying the fuel flow. Increasing demand in the dryer or in the steam system tends to draw more heat out of the combustor, and this is compensated for by firing more fuel.

Steam temperature is controlled by the desuperheater located between the two superheaters in the convective pass. The steam temperature is not strongly affected by the flow rate of solids through the FBHE because the superheater is a small part of the total FBHE surface and is located at the hot end of the exchanger.

Steam flow is controlled by varying the solids flow through the FBHE evaporator. This solids flow is controlled by M-304 and M-305, control valves in the solids ducts at the inlet of the fluid bed heat exchangers.

To illustrate the control scheme, assume the dryer plant is at one-third load and is brought to full load. Bear in mind that the control actions are simultaneous, not sequential. The control actions are not accompanied by wide swings in the controlled variables.

As the coal feed to the dryer increases, the outlet gas temperature falls. The system opens the combustion air bypasses to provide hotter flue gas. The temperature of the combustion air decreases, tending to cool down the combustor. The system calls for more fuel and more combustion air. In accordance with safe practice, the combustion air flow is increased before the fuel flow is increased on rising demand. On falling demand, the fuel flow is reduced

before the air flow is reduced. Changes in demand are always accomplished with a higher than normal oxygen content in the fluegas to avoid the possibility of a carbon-monoxide-rich, oxygen-poor flue gas. The fuel increase causes an increase in the gas flow from the hot cyclones. The system reduces, then stops, the dilution air flow. The increased flue gas flow increases the heat transfer in the economizer and the superheaters in the convective pass. The flow rate and the temperature of the steam both go up. The system starts the water flow to the desuperheater and reduces the FBHE solids flow to compensate. Finally, because of the increased fuel feed rate, ash is withdrawn at a higher rate from the FBHE outlet drain.

5.1.6 Drying Plant

The drying plant equipment will operate at slightly different conditions after the cogeneration plant comes on line. The gas flow will be 752,600 lb/hr containing 2600 lb/hr solids. Because of its small size (approximately minus 400 mesh), most of the flyash will pass through the coal dryer and the cyclones and will end up in the venturi scrubber.

The makeup water flow to the scrubber and the slurry flow to the thickener will be increased so that the solids concentration in the slurry can be held to 5%. The budget includes replacement of the slurry pump (FMC Item No. 6426) and an allowance for 500 feet of piping. There is no need for modifications to the Recirculation Pump (FMC Item No. 6425) or to the venturi scrubbers themselves.

The ID Fan must operate whenever the cogeneration plant is running. Both Luscar and Lurgi have been in contact with Novenco, the fan manufacturer. Novenco recommends the use of hardened wear plates to increase the run time up to 8 months. Novenco also recommends installation of a turning gear to assist in startup of the fan and to reduce the amount of current drawn by the motor during acceleration.

The fluegas duct from the boiler island to the dryer building will enter the latter through the north wall adjacent to the dryer. A bypass around the dryer will be included, and this will run outside the building, through the roof, and into the existing duct.

The cogeneration plant was carefully designed to work with the gas cleanup system, and only a few changes (reference, page 5-20) need to be made to the existing equipment in the dryer building.

5.1.7 Ash Handling

The ash-handling equipment will collect ash from two points within the boiler island, cool it to 200 °F (an acceptable temperature for the existing washery plant belts), and deliver it to the rejects conveyor in the washery building. There is no provision for ash storage. In the event that the rejects belt is out of service the cogeneration plant will not operate.

This study offers ash transport entirely by belt conveyors. It is felt that this offers reliable transport using equipment with which both Luscar and TransAlta feel comfortable. There appear to be no interference problems with the conveyor runs. Pneumatic transport is an alternate method of returning ash to the washery. This method was rejected primarily because of the need for air/solid separation equipment in the existing building, where space is somewhat limited.

5.1.8 Plant Building Heat Distribution

A central building heat distribution system was considered as an option. This system was based on extracting low-pressure steam from the steam turbine at a maximum rate of 50 million Btu/hr and transferring this heat to a circulating glycol system. Based on peak heat load and location data provided by Luscar, a preliminary design concept using three main glycol circuits and 40 heating stations was developed. In addition, a glycol-to-glycol exchanger was provided in the administration building in order to interface with the existing glycol circuit in this building.

The boiler plant and turbine have been sized to provide extraction steam at a maximum rate of 50 million Btu/hr while simultaneously generating the desired 30 MW power.

5.2 MAJOR EQUIPMENT LIST AND DUTY SPECIFICATIONS

The major equipment list is presented in the following pages and is organized into the following categories:

a) Equipment located in Washery Building

b) Fuel and ash materials handling equipment

c) Boiler island

d) Turbine building equipment

e) Water treatment area

f) Cooling tower

g) Equipment located in existing Dryer Building

h) Plant building heat distribution

Equipment Located in the Washery Building

Item	Qty	Description	Capacity
D-101 Heavy Media Cyclone Reject Screen Outlet Diverter	1	Flop gate, actuated from control room.	140 ton/hr
M-101 Heavy Media Cyclone Reject Screen Chute	1	Steel construction.	140 ton/hr
D-102 Spiral Classifier Coarse Fraction Diverter	1	Flop gate, actuated from control room.	17 ton/hr
M-102 Spiral Classifier Coarse Fraction Chute	1	Steel construction.	17 ton/hr
M-103 Fuel Conveyor	1	150 ft x 24" From washery to magnetite storage shed.	157 ton/hr
M-104 Fuel Conveyor	1	50 ft x 24" From magnetite shed to pickup point.	157 ton/hr
M-603 Ash Conveyor	1	50 ft x 24" From pickup point through magnetite shed.	45 ton/hr
M-604 Ash Conveyor	1	90 ft x 24" From magnetite shed to existing rejects conveyor.	45 ton/hr

Solids Handling Equipment
(Refer to Area Plan P-62504-10)

Item	Qty	Description	Capacity
M-121 Fuel Conveyor	1	From magnetite shed to 30-hour storage. The maximum flow rate occurs when material is being reclaimed from the 14-day pile. 480 ft x 36"	420 ton/hr 60 hp
M-122 Tripper Conveyor	1	Located above the 30-hour storage bin. 110 ft x 24"	420 ton/hr 15 hp
M-123 Fuel Conveyor	1	From M-121 to 14-day pile. 150 ft x 24"	180 ton/hr 15 hp
M-124 30-hour Bunker Reclaim Belt	1	Beneath 30-hr bunker. 110 ft x 60"	110 ton/hr 50 hp
M-125 14-day Pile Reclaim Belt	1	From G-101 to M-121 215 ft x 36"	420 ton/hr 50 hp
M-126 Boiler Island Feed Belt	1	From M-124 to coal feed bin. 400 ft x 24"	110 ton/hr 25 hp
M-601 Ash Conveyor	1	From boiler island to M-602. 90 ft x 24"	50 ton/hr 5 hp
M-602 Ash Conveyor	1	From M-601 to magnetite shed. 150 ft x 24"	50 ton/hr 5 hp
G-101 Frozen Coal Cracker and Hopper	1	Roll crusher and hopper drop-off point for reclaim from 14-day pile.	420 ton/hr
V-301 30-Hour Bunker	1	30 ft x 80 ft x 70 ft high complete with building and instrument panel.	3030 tons

Boiler Island Equipment

Item	Qty	Description	Capacity
V-200 Coal Feed Bin	1	Steel. 16' dia. cylindrical height 42'6". Cone height 22'. Total height 64'6".	2 hr holdup 202 tons
M-202/M-203 Fuel Weigh Feeders	2	One active, one spare. Belt type feeder, Merrick or equal. Minimum flow, 14 stph. Maximum flow, 101 stph.	Design flow 110 stph
V-204/V-205 Fuel Crusher/ Dryers	2	Impact mill. Hot air is injected to remove surface moisture from the fuel and to convey it into the combustor vessel.	Inlet, -1/2" Exit, -1/4" 75 hp
F-303 Combustor Vessel	1	Cylindrical, refractory-lined with steel shell. Dual air inlet. Single fuel feed port.	1600°F 101 stph fuel feed
F-302 Combustor Windbox	1	With refractory grate and fluidizing nozzles.	
B-301/B-302/B-303/ B-304 Start-up Burners	4	These will be specified for natural gas, propane, or fuel oil, depending on what fuel is available on site.	20 mm Btu/hr, each
D-320/D-321 Ducts from Combustor to Hot Cyclones	2	Refractory-lined with steel shell.	5'6" x 16'9" inside dimensions
S-360/S-361 Hot Cyclones	2	High efficiency. Refractory-lined with steel shell.	695,000 acfm at 1600°F
D-340/D-341 Ducts from Hot Cyclones to Backpass	2	Refractory-lined with steel shell.	11' ID

Boiler Island Equipment (Continued)

Item	Qty	Description	Capacity
E-503 Convective Pass	1	Approximately 34' wide x 19' deep x 100' high	
Superheater		High temp. Section: 2" OD SA-210-A1 tube construction, 0.165" wall thickness. 28 assemblies on 8" centers, 6 tube rows/assembly on 4" centers.	20.0 MM Btu/hr
		Low temp. Section: 2" OD SA-209-T1 tube construction, 0.165" wall thickness. 28 assemblies on 8" centers, 12 tube rows/assembly on 4" centers.	36.7 MM Btu/hr
Interstage Desuperheater		Control range 33% to 100% of full dryer load. At zero dryer load, the steam system operates the same as at 33% load.	10300 lb/hr max. BFW input
Economizer		2" OD SA-210-A1 tube construction, 0.165" wall thickness. 28 assemblies on 8" centers, 50 tube rows/ assembly on 4" centers.	102.9 MM Btu/hr
Air Preheater		2" OD, 14 BWG tube construction. Hot end material SA-209-T-1. Cold end material SA-210-A-1.	78.3 MM Btu/hr
Multiclone		Three multiclone assemblies in parallel. Pressure drop is 2.5 inches of water. Emissions not to exceed 0.65 G/ACF.	Approx. 90% efficiency

Boiler Island Equipment (Continued)

Item	Qty	Description	Capacity
V-501 Steam Drum	1	Design Pressure 1400 psig. 60" nominal I.D. 18'7" T/T. ASME material specification SA-515-70.	275,000 lb/hr
V-360/V-361 Cyclone Seal Pots	2	Refractory-lined with carbon steel shell. Includes duct from cyclone to seal pot and duct from seal pot to combustor.	
D-345/D-346 Duct from Seal Pot to FBHE	2	Refractory-lined with steel shell.	
M-304/M-305 Ash Control Valve	2	In duct from seal pot to fluid bed heat exchanger.	1600°F
E-360/E-361 Fluid Bed Heat Exchangers	2	Refractory-lined and waterwall construction. Approximately 24' x 12' x 16'6" high, inside dimensions.	
FBHE Superheater Bundle		Tube bundle assemblies constructed from 2" O.D. SA-213 T-22 material.	26.2 MM Btu/hr
FBHE Evaporator Bundles		Tube bundle assemblies constructed from 2" O.D. SA-213 T-22 material.	178.9 MM Btu/hr

Boiler Island Equipment (Continued)

Item	Qty	Description	Capacity
D-362/D-363 Solids Duct from FBHE to Combustor	2	Refractory-lined with steel shell.	
D-364/D-365 Air Duct from FBHE to Combustor	2	Refractory-lined with steel shell.	60" ID
D-366/D-367 Duct from FBHE to FBHE Ash Cooler	2	Refractory-lined with steel shell.	
M-302/M-303 Ash Control Valve	2	In duct from outlet of FBHE to FBHE ash cooler.	65,600 lb/hr 900°F
D-351 Duct from Combustor to FBHE Ash Cooler	1	Refractory-lined with steel shell.	
M-301 Ash Control Valve	1	In duct from combustor to FBHE ash cooler.	17,000 lb/hr
E-501 FBHE Ash Cooler	1	Fluid bed ash cooler. Steel construction. 65,600 lb/hr cooled from 860°F to 200°F. When no steam is produced, 17,000 lb/hr cooled from 1600°F to 200°F.	10.2 MM Btu/hr 6.1 MM Btu/hr
E-501 Multiclone Ash Cooler	1	Fluid bed ash cooler. Steel construction. 26,000 lb/hr cooled from 759°F to 200°F. When no steam is produced, 11,500 lb/hr cooled from 905°F to 200°F.	3.4 MM Btu/hr 1.9 MM Btu/hr
M-621 Ash Conveyor	1	From E-502 to M-601 Length 48' Width 24" 5 hp	26,000 lb/hr

Boiler Island Equipment (Continued)

Item	Qty	Description	Capacity
C-501 Primary Air Fan	1	Centrifugal fan. Normal flow 59,400 ICFM. No Steam Case: 71,400 ICFM.	1250 bhp full load, 1350 bhp no steam
C-502 Secondary Air Fan	1	Centrifugal fan. Normal flow 70,200 ICFM. No Steam Case: 84,500 ICFM.	900 bhp full load, 1030 bhp
C-503/C-504 FBHE Blower	2	Positive displacement blower. Normal flow 9450 ICFM.	257 bhp
C-505/C-506 Seal Pot Blower	2	Positive displacement blower. Normal flow 1000 ICFM.	32 bhp

Turbine Building

Item	Qty	Description	Capacity
Turbine	1	Multi-valve, multi-stage steam turbine, 3 uncontrolled extractions and condensing to 2" HgA, lubrication/ control oil console, electronic governor control system, Westinghouse Canada Model D-236-12 or equal.	900°F, 1200 psig steam @ 275,535 lb/h
Generator	1	Totally enclosed water/air cooled (TEWAC) synchronous generator with brushless exciter and automatic voltage regulator, Westinghouse Canada or equal.	30 MW gross electrical
Condenser	1	Surface type, double cooling water pass, 36,892 ft^2 heat exchange surface; turbine exhaust pressure @ 2" Hg.	183 MM Btu/h
Feedwater Heaters	3	2 low pressure, 1 high pressure shell and tube heat exchangers, 18 BWG admiralty tubes, carbon steel shell.	10 MM Btu/h
Condensate Pumps	2	6 x 4 x 11 D 1012 centrifugal pump carbon steel construction, mechanical seal, 25 HP electric motor, TDH = 100 ft.	600 USGPM
Deaerator	1	Tray type deaerator, steel shell, stainless steel trays, baffles and spray valves.	275,000 lb/h
Overhead Crane	1	24/2.4 ft/min. dual speed; 30' travel, 40' span, 26' hoist; trolley speed 50 ft/min., bridge speed 50 ft/min., 48.2 HP electric hoist motor, push button operation.	25 ton

Water Treatment Area

Item	Qty	Description	Capacity
Demineralizer			235 USGPM
Strong Acid Cation	2	66" diameter, 168" height	194 ft^3
Degassifier	1	48" diameter, 216" height	100 ft^3
Strong Base Anion	2	60" diameter, 96" height	78 ft^3
Mixed Bed	2	54" diameter, 96" height	34 ft^3
Acid System	1	Incl. pumps, tanks	
Caustic System	1	Incl. pumps, tanks	
Condensate Polishing			546 USGPM
Mixed Bed	2	36" diameter, 96" height; dual stream automatic regeneration.	

Cooling Tower

Item	Qty	Description	Capacity
Cooling Tower	1	2 cell tower, wooden splash bars, 10°F approach temp., circulating water flow 34,000 USGPM, 183 fan BHP, concrete basin, Marley, Inc. Model 674-4-02 or equal.	186 MM Btu/h
Cooling Water Circ. Pumps	3	3 stage vertical turbine pump, 116 ft TDH, 16" discharge, 1175 RPM, including 400 HP, 440V electric motor drive.	11000 USGPM
Raw Water Pumps	2	5 stage vertical turbine pump, 150 ft TDH, 10" discharge, 1800 RPM, including 25 HP, 440 V electric motor drive.	450 USGPM

Located in Existing Dryer Building

Item	Qty	Description	Capacity
D-801 Fluegas Duct	1	From backpass to existing coal dryer. 9' x 9' square. Externally insulated steel. Complete with dampers, expansion joints, bypass, and quench.	468,000 acfm 905°F max. operating temperature
P-801 Venturi Scrubber Slurry Pump	1	Centrifugal pump. Slurry concentration is 5% solids.	200 USGPM 20 PSI TDH
X-801 Slurry Piping	1	2" Sch. 80 pipe from venturi scrubber to existing clarifier.	Approx. 500 ft.
X-802 Part of ID Fan	1	Wear liner for existing ID fan. Supplied by Novenco.	6-8 months service
X-803 Part of ID Fan	1	Turning gear for existing ID fan. Supplied by Novenco.	40 rpm

Plant Building Heat Distribution

Item	Qty	Description	Capacity
P-901 Glycol Circulation	1 + Spare	For 50% ethylene glycol solution, carbon steel	1500 USGPM
E-901 Glycol Heat Exchanger	1	54" ID shell, 30 ft. length, 8300 sq. ft. surface, carbon steel	66.7 MM Btu/hr
E-902 Glycol Vent Condenser	1	20 sq. ft. surface, 10 USGPM cooling water	100,000 Btu/hr
I-901 Glycol Expansion Tank	1	Carbon steel	3'6" dia., by 7'0"
D-901 Glycol Piping	-	Size (in.) / Linear ft.: 1.5 — 2,800 2 — 2,200 3 — 1,000 4 — 3,060 6 — 860 8 — 260 10 — 380	STD. weight steel pipe
Heating Registers:		Inlet 275°F, Outlet 160°F	Million But/hr
E-950	1	175 USGPM	8.8
E-951	7	60 "	3.0
E-952	1	50 "	2.5
E-953	5	40 "	2.0
E-954	4	30 "	1.5
E-955	1	25 "	1.2
E-956	1	15 "	0.8
E-957	1	13 "	0.6
E-958	3	10 "	0.5
E-959	6	7 "	0.3
E-960	10	4 "	0.2
E-910 E-911 Heat Exchangers for office building	1 1	Shell and tube, two identical units in series, 1400 sq. ft. x 2	4 MM Btu/hr; 6 MM Btu/hr

5.3 CONCEPTUAL PLANT LAYOUT

The area plan is shown on Drawing 62504-10.

The 14-day fuel storage pile and the 30-hr bunker are both located in the triangular plot of ground to the northeast of the product load-out pile. The ground elevation in this area is approximately 30 ft above the elevation at the boiler island. It is not practical to locate the 30-hr bunker where the propane tanks are presently located because of slope requirements for conveyor M-126; the top of the surge bin V-200 is 100 ft above grade.

The boiler island is located adjacent the dryer building to provide as short a length as possible for the hot flue gas duct. The turbine island has been located directly adjacent to the boiler island, thereby minimize piping runs.

For reasons of safety, it is recommended that the propane tanks be moved to a location further from the combustion plant.

5.4 CAPITAL COST ESTIMATE

5.4.1 Methodology

Costs were estimated in a semi-detailed manner, drawing upon previous experience with similar type projects. The basic approach was to first estimate costs for direct materials and equipment, along with the associated erection labour, and then to estimate the cost of engineering and other applicable indirect costs. A summary of the techniques used for each of the foregoing estimate components is as follows:

- Equipment - based on preliminary equipment sizes, budget quotations were obtained for the following equipment items:
  - Fuel and ash handling system, including 30-hr bunker and main conveyors
  - Air fans and blowers
  - Multiclone
  - Turbine/generator, and condenser
  - Feed water heaters and deaerator
  - Condensate pumps
  - Demineralizer and condensate polisher
  - Cooling tower, and water circulating pumps
  - Raw water pumps
  - ID fan upgrade

  Costs for remaining equipment items were prorated from previous quotations and other in-house estimating data.

- Material - the cost of most direct materials was prorated from previous projects. For certain materials (e.g. boiler island siding), a "conceptual material take-off" was developed and subsequently priced.

- Construction - erection manhours were factored from equipment and material costs/quantities, based on previous project experience. Direct labor costs were estimated using an appropriately weighted average wage rate. Indirect field cost (e.g. supervision, temporary construction and consumables, construction equipment) was factored from direct labor cost, based on previous experience.

- Engineering/Other Indirects - engineering costs were factored, based on the overall project scope. Factors reflect previous project experience. Other indirects (e.g. start-up assistance) were estimated based on similar projects.

- Contingency - The total project estimate includes approximately 10% contingency.

5.4.2 Confidence Limit

The expected accuracy of the total project cost is on the order of ± 20%.

5.4.3 Estimate Exclusions

Estimate exclusions include:

- Building heat distribution system to replace existing propane-based systems (this is covered separately in paragraph 5.4.5)
- Escalation (all costs are fourth quarter 1984, CDN dollars)

5.4.4 Estimate Summary

	Cost Estimate (CDN Dollars)
Fuel and Ash Handling	6,500,000
Boiler Plant Equipment	21,200,000
Turbine Generator	6,700,000
Structures and Improvements	4,500,000
Raw Water Supply	400,000
Cooling Tower	1,400,000
Water Treatment	1,100,000
Switchgear Upgrading	800,000
Construction Camp, including Subsistence for Construction Workers	1,300,000
Travel for Construction Workers	700,000
Total	45,000,000

5.4.5 Option for Building Heat Distribution System

A very preliminary estimate was prepared for the glycol-based heat distribution system. This estimate was based solely on the prepared equipment list using generalized cost factors for equipment, piping, installation, engineering and other indirect costs. The total incremental installed cost for this option is estimated at $2,500,000 (CDN dollars).

The desirability of this option will have to be assessed by Luscar in relation to the resulting savings in propane consumption.

5.5 OPERATING REQUIREMENTS/COSTS

It is visualized that Luscar will operate the fuel handling/ash handling facilities; TransAlta will most likely operate the power plant. Operating costs have therefore been separated into these conditions.

Operating and maintenance labour were assessed with the assistance of Luscar and TransAlta to reflect labor practices and costs at The Coal Valley Location.

5.5.1 Operating Personnel

Annual costs given below are all-inclusive costs (salary plus benefits.)

(a) Power Station (TransAlta)

	Annual Cost (Canadian $)
1 Plant manager	80,000
1 Clerk/secretary	25,000
5 Shift supervisors	260,000
10 Plant operators	435,000
Subtotal	$ 800,000

(b) Fuel/Ash Handling (Luscar)

	Annual Cost (Canadian $)
4 Plant operators	156,000
2 Front-end loader operators	82,000
Subtotal	$ 238,000
Total operating personnel, Luscar plus TransAlta	$1,038,000

5.5.2 Maintenance Supplies and Labour

(a) Power Station (TransAlta)

Maintenance Labour		Annual Cost (Canadian $)
1 Electrician	(CFB Plant)	45,000
1 Mechanic	"	45,000
- Other Labour	"	150,000
- Other Labour	(Turbine)	30,000
Subtotal		$ 270,000
Maintenance Supplies		
CFB Plant		240,000
Turbine		30,000
Subtotal		$ 270,000
Total Maintenance (TransAlta)		$ 540,000

(b) Fuel/Ash Handling (Luscar)	Annual Cost (Canadian $)
4 Maintenance men (conveyor/dust collectors, etc.)	180,000
Maintenance Supplies	
Coal delivery	55,000
Total Maintenance (Luscar)	$ 235,000

(c) Total maintenance cost for complete facility, (a) plus (b), is thus estimated to be $540,000 plus $235,000, or approximately $775,000.

Historical, published data on circulating fluid bed calciner, when scaled up to the present facility on the basis of total annual solids (ash) flow rate yields an annual average maintenance cost of approximately $480,000 Canadian dollars. This later figure is consistent with the above estimate when the additional maintenance for materials handling and turbine are taken into account.

Furthermore, the estimated annual maintenance cost of $775,000 represents approximately 1.8% of the total investment of the facility. This percentage is considered to be reasonable for a plant of this nature.

5.5.3 Fuel Consumption

Fuel consumption at maximum load is 101 short ton/hr.

5.5.4 Electric Power Consumption

Electric power consumption at a maximum production of 30 MW produced power and 600 stph coal drying:

	kW
Power Station (TransAlta)	2,900
Fuel/Ash Handling (Luscar)	120
Total Power	3,020 kW

5.5.5 Summary of Operating Requirements/Costs

Component	Unit	Power Plant (TransAlta)	Fuel Handling (Luscar)	Totals
Operating Labour	$	800,000	238,000	1,038,000
Maint. Labour	$	270,000	180,000	450,000
Maint. Supplies	$	270,000	55,000	325,000
Fuel Consumption	stph	-	101	101
Power Consumption	kW	2,900	120	3,020

5.6 AVAILABILITY

The plant has been designed to operate:

(a) Power plant and coal drying plant simultaneously.

(b) Power plant alone when drying plant is down for inspection and maintenance.

(c) Generation of flue gas for drying plant when turbine/generator facility is down.

The availability of the plant in terms of dryer operation and power generation is therefore considered separately below.

5.6.1 Generation of Flue Gas for Drying Plant

It is normal practice at Coal Valley to shut down the coal drying plant every Wednesday for a 12-hr period for plant inspection and maintenance. This, combined with the annual plant shut down leads to a yearly operating time of 6200 hours for the drying plant.

The circulating fluid bed combustor is designed to operate at essentially all times when the drying plant is in operation. Provisions have been made for 30 hour storage of fuel (plus a back-up of 14 days fuel in an open stockpile). It is therefore reasonable to assume that the drying plant will continue to operate 6200 hours annually.

5.6.2 Power Production

It is assumed that the CFB boiler/turbine-generator facility will be down for three weeks per year for a scheduled annual inspection and maintenance shutdown. This represents a loss of about 21 days of operation, or a contribution to unavailability of (21/365) (100), or 5.8%.

Operating experience on Lurgi circulating fluid bed systems indicate the following annual plant availability factors (calculated on the basis of 365 days, and including scheduled annual down-time for inspection and maintenance):

- CFB calciners - 92 to 98% availability
- CFB boiler (VAW plant at Luenen, West Germany) - over 90% availability during first year of operation.

Based on the above experience, and assuming that the plant will be properly serviced and maintained, a mature year availability of 92% for the CFB combustor and boiler appears achievable. This represents 8% of 365 or 29 days down-time annually of which 21 may be assumed to be the annual scheduled down-time, and 29-21, or 8 days are unscheduled down-time days.

It is recommended that an additional unscheduled down-time of about 3% be allowed for the turbine/generator set, condenser and cooling tower.

An additional 3% unscheduled downtime is included as an allowance to account for the remote location of the plant and possible interference due to the coupling of the fuel and ash systems to the washery and the offgas to the coal drying plant. The analysis does assume, however, that the existing ID fan in the gas scrubbing system is upgraded as previously described.

Based on the above, the overall available hours for power production is estimated at about 7,500 hours per year, as shown below:

			Hours
Annual hours:	365 x 24	=	8,760
Scheduled annual plant shutdown:	21 x 24	=	504
Unscheduled CFB boiler downtime:	8 x 24	=	192
Unscheduled downtime for turbine plus other facilities:	365 x 24 x 3%	=	264
Allowance for remote location and plant tie-in:	365 x 24 x 3%	=	264
Available hours:	8760 -504 -192 -264 -264	=	7,536

Overall, yearly availability = (7,536/8,760) (100), or 86%.

It is noted that the North American Electric Reliability Council has determined an average plant availability factor (1 to 99 MW plants) of 86.5%. Considering the advancement of CFB technology as compared to conventional boiler plants (lower temperature operation, avoidance of slagging conditions, overall simplicity of plant), an overall 86% availability is considered to be achievable at Coal Valley.

5.7 THERMAL EFFICIENCY

The thermal efficiency of the plant is 76% based on the higher heating value of the fuel. This figure applies to operation at full dryer load. The summary balance at full load is as follows:

Heat Input:	Btu/Lb Fuel	% of Input
Fuel HHV	3040.0	100.00
Heat to Process:		
Steam	1691.2	55.63
Dryer	610.9	20.10
Subtotal	2302.1	75.73

Heat Losses:	Btu/Lb Fuel	% of Input
Moisture Losses to Flue Gas	428.1	14.08
Dry FLue Gas	94.9	3.12
Sensible Heat of Ash	78.3	2.57
Unburned Carbon	67.1	2.21
Radiation and Unaccounted	69.5	2.29
Subtotal	737.9	24.27

The following figures show an efficiency of 75% at one-third dryer load:

Heat Input	Btu/Lb Fuel	% of Input
Fuel HHV	3040.0	100.00
Heat to Process		
Steam	2038.3	67.05
Dryer	245.1	8.06
Subtotal	2283.4	75.11
Heat Losses		
Moisture	428.1	14.08
Dry Fluegas	94.9	3.12
Dilution Air	10.8	0.36
Sensible Heat of Ash	71.1	2.34
Unburned Carbon	67.1	2.21
Radiation and Unaccounted	84.6	2.78
Subtotal	756.6	24.89

5.8 PROJECT SCHEDULE

A preliminary project bar chart schedule is shown on the following page. An overall project time table from project award through completion of performance testing is indicated. The construction period is approximately 12 months.

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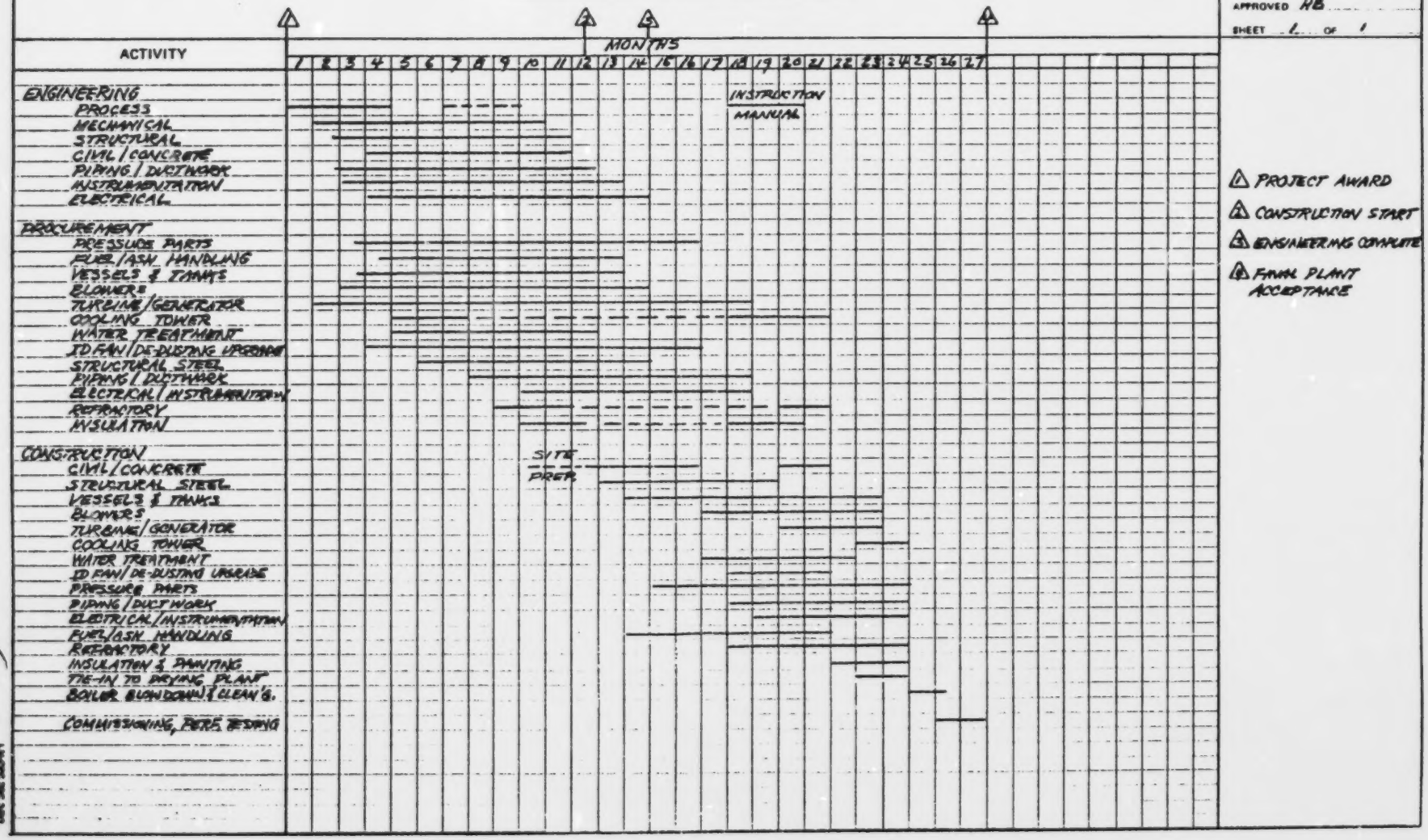
LUSCAR COAL TAILINGS UTILIZATION STUDY
OVERALL BAR CHART SCHEDULE

PROJECT 62504

REV ..... DATE 2-22-85

APPROVED HB

SHEET 1 OF 1



1. PROJECT AWARD
2. CONSTRUCTION START
3. ENGINEERING COMPLETE
4. FINAL PLANT ACCEPTANCE

6. CONCLUSIONS

6.1 The production of 30 MW power with simultaneous production of hot flue gas for drying 600 tons per hour coal by means of a circulating fluid bed combustion plant is technically feasible at Coal Valley. The gas handling system in the existing drying plant can be used to de-dust the waste gas, although some modifications will be necessary.

6.2 The combustion plant can be designed to operate under the extreme conditions of:

- Producing power while the coal drying plant is shut down;
- Providing drying gas for the coal drying plant when the turbine/generator is shut down.

6.3 Total investment cost for the CFB power plant complex including materials handling, boiler plant, turbine/generator, and associated facilities is estimated to be 45 million Canadian dollars, equivalent to approximately 1500 dollars per kilowatt.

6.4 Based on operating practices and unit costs appropriate to the Coal Valley site, the following annual operating requirements/costs are estimated for the power complex:

- Operating labour:	$1,040,000
- Maintenance labour and supplies:	775,000
- Station Service power consumption:	3.0 MW
- Fuel (washery rejects) consumption:	101 stph

6.5 The power/hot gas plant should be able to meet the following annual operating hours:

- Hot flue gas for coal drying plant: 6200 hours, according to current operating practice of washery/drying plant;
- Power generation: Approximately 7500 hours, corresponding to an overall availability of 86%.

6.6 The coal tailings should burn efficiently in a circulating fluid bed combustor. However, a pilot plant test burn program should be carried out to confirm operating temperature, excess air requirements, and degree of sulfur capture without limestone injection.

6.7 In general, the concepts worked out in this report for the Coal Valley site may be applicable to other mine sites having similar coal rejects, drying requirements and possibilities for power acceptance by the local utility.

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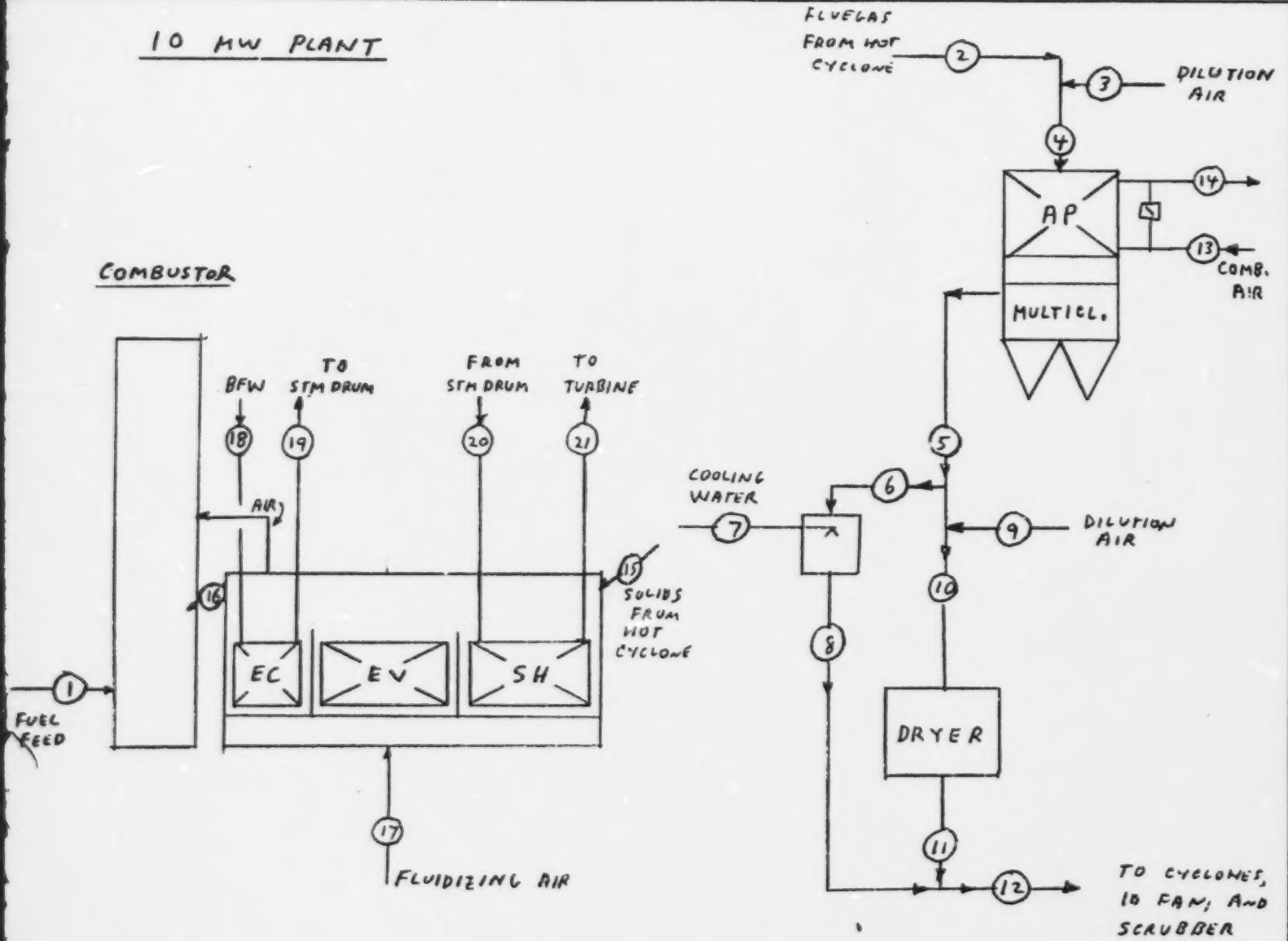
MATERIAL BALANCE SUMMARIES

10 MW PLANT



LURGI LURGI CORPORATION

CALCULATION SHEET

SUBJECT: ALTERNATE I

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CALCULATION SHEET

SUBJECT: ALTERNATE I

REF. NO. OR JOB NO.

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BY:

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APPRD:

10 MW PLANT

DRYER LOAD 600 TPH

DUTY, BTU/HR

FBHE SUPERHEATER 24.3×10^6
FBHE EVAPORATOR 59.7×10^6
FBHE ECONOMIZER 30.3×10^6

AIR PREHEATER 34.5×10^6
DRYER 123.4×10^6

	COAL FEED 1	FLUEGAS FROM CYCL. 2	DILUTION AIR 3	TO AIR PREHEATER 4	FROM AIR PREHEATER 5	GAS TO QUENCH 6	QUENCH WATER 7	GAS FROM QUENCH 8
LB/HR	106,177	398,128	195,198	593,326	593,326	0	0	0
DEG F	-	1600	40	1150	944	-	-	-

	DILUTION AIR 9	GAS TO DRYER 10	GAS FROM DRYER 11	GAS TO CLEANUP 12	COMBUSTION AIR 13	HOT COMB. AIR 14	SOLIDS TO FBHE 15	SOLIDS FROM FBHE 16
LB/HR	45,314	638,640	710,640	710,640	136,425	136,425	540,223	540,223
DEG F	40	887	160	160	40	527	1600	750

	FLUIDIZING AIR TO FBHE 17	BOILER FEEDWATER 18	BFW FROM ECONOMIZER 19	SATURATED STEAM 20	SUPERHEATED STEAM 21			
LB/HR	47,702	94,190	94,190	91,364	91,364			
DEG F	40	230	530	587	900			

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CALCULATION SHEET

SUBJECT: ALTERNATE I

REF. NO. OR JOB NO.

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BY:

CHKD:

APPRD:

10 MW PLANT

DRYER LOAD 200 TPH

DUTY, BTU/HR

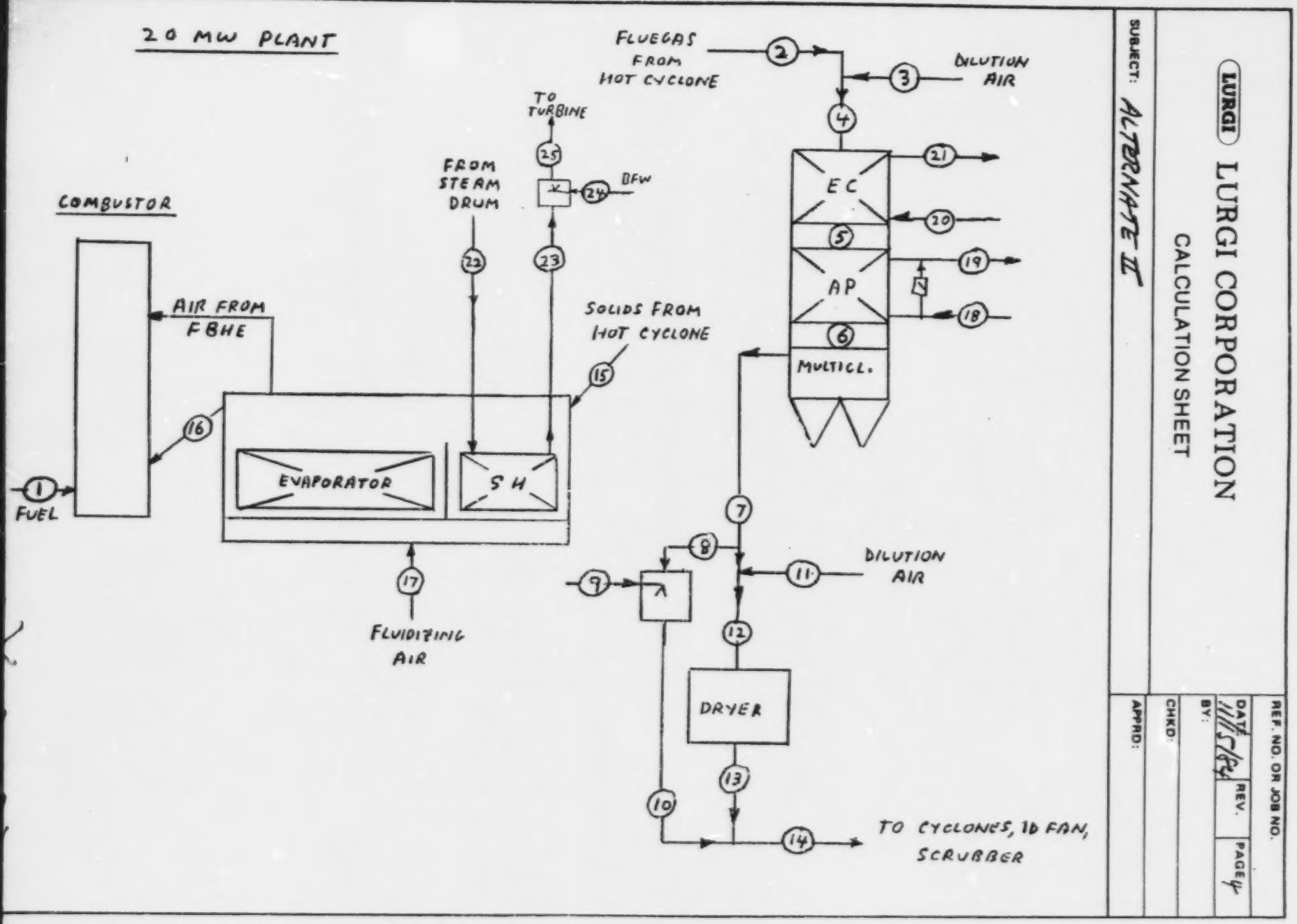
FBHE SUPERHEATER 24.3×10^6
FBHE EVAPORATOR 59.7×10^6
FBHE ECONOMIZER 30.3×10^6

AIR PREHEATER 44.3×10^6
DRYER 41.1×10^6

	COAL FEED 1	FLUEGAS FROM CYCL. 2	DILUTION AIR 3	TO AIR PREHEATER 4	FROM AIR PREHEATER 5	GAS TO QUENCH 6	QUENCH WATER 7	GAS FROM QUENCH 8
LB/HR	72,655	272,431	133,569	406,000	406.000	100,634	14,246	114,880
DEG F	–	1600	40	1150	760	760	40	160

	DILUTION AIR 9	GAS TO DRYER 10	GAS FROM DRYER 11	GAS TO CLEANUP 12	COMBUSTION AIR 13	HOT COMB. AIR 14	SOLIDS TO FBHE 15	SOLIDS FROM FBHE 16
LB/HR	266,394	571,760	595,760	710,640	93,355	93,355	540,223	540,223
DEG F	40	445	160	160	40	1000	1600	750

	FLUIDIZING AIR TO FBHE 17	BOILER FEEDWATER 18	BFW FROM ECONOMIZER 19	SATURATED STEAM 20	SUPERHEATED STEAM 21			
LB/HR	47,702	94,190	94,190	91,364	91,364			
DEG F	40	230	530	587	900			



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LURGI LURGI CORPORATION

CALCULATION SHEET

SUBJECT: ALTERNATE II

20 MW PLANT

DRYER LOAD: 600 TPH

DUTY, BTU/Hr

FBHE SUPERHEATER	48.7×10^6
FBHE EVAPORATOR	107.3×10^6
ECONOMIZER	71.8×10^6
AIR PREHEATER	22.9×10^6
DRYER	127.4×10^6

	FUEL 1	FLUEGAS FROM CYCL. 2	DILUTION AIR 3	TO ECONOMIZER 4	TO AIR PREHEATER 5	FROM AIR PREHEATER 6	FROM MULTICLONE 7	TO QUENCH 8
Lb/Hr	142,673	534,976	102,598	637,574	637,574	637,574	637,574	0
DEG F	-	1600	40	1386	1000	874	874	-

	QUENCH WATER 9	GAS FROM QUENCH 10	DILUTION AIR 11	TO DRYER 12	FROM DRYER 13	TO C.C.U. 14	SOLIDS TO FBHE 15	SOLIDS FROM FBHE 16
Lb/Hr	0	0	1066	638,640	710,640	710,640	878,807	878,807
DEG F	-	-	40	872	160	160	1600	900

	FBHE FLUID. AIR 17	COMBUSTION AIR 18	HOT COMB. AIR 19	BOILER FEEDWATER 20	BFW FROM ECONOMIZER 21	STEAM TO SUPERHEATER 22	STEAM FROM SUPERHEATER 23	BFW TO DESUPERHEATER 24
Lb/Hr	58,011	400,297	400,297	186,457	186,457	182,728	182,728	0
DEG F	40	40	291	230	580	587	900	-

	STEAM TO TURBINE 25							
Lb/Hr	182,728							
DEG F	900							

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LURGI LURGI CORPORATION

CALCULATION SHEET

SUBJECT: ALTERNATE III

20 MW PLANT

DRYER LOAD: 200 TPH

DUTY, BTU/HR

FBHE SUPERHEATER	48.7×10^6
FBHE EVAPORATOR	108.0×10^6
ECONOMIZER	71.2×10^6
AIR PREHEATER	33.7×10^6
DRYER	41.1×10^6

	FUEL 1	FLUEGAS FROM CYCL. 2	DILUTION AIR 3	TO ECONOMIZER 4	TO AIR PREHEATER 5	FROM AIR PREHEATER 6	FROM MULTICLONE 7	TO QUENCH 8
LB/HR	99,840	374,365	7,503	381,868	381,868	381,868	381,868	0
DEG F	-	1600	40	1575	950	640	640	-

	QUENCH WATER 9	GAS FROM QUENCH 10	DILUTION AIR 11	TO DRYER 12	FROM DRYER 13	TO G.C.U. 14	SOLIDS TO FBHE 15	SOLIDS FROM FBHE 16
LB/HR	0	0	304,772	686,640	710,640	710,640	884,906	884,906
DEG F	-	-	40	394	160	160	1600	902

	FBHE FLUID. AIR 17	COMBUSTION AIR 18	HOT COMB. AIR 19	BOILER FEEDWATER 20	BFW FROM ECONOMIZER 21	STEAM TO SUPERHEATER 22	STEAM FROM SUPERHEATER 23	BFW TO DESUPERHEATER 24
LB/HR	58,010	262,703	262,703	186,245	186,245	182,520	182,520	208
DEG F	40	40	568	230	577	587	902	230

	STEAM TO TURBINE 25							
LB/HR	182,728							
DEG F	900							

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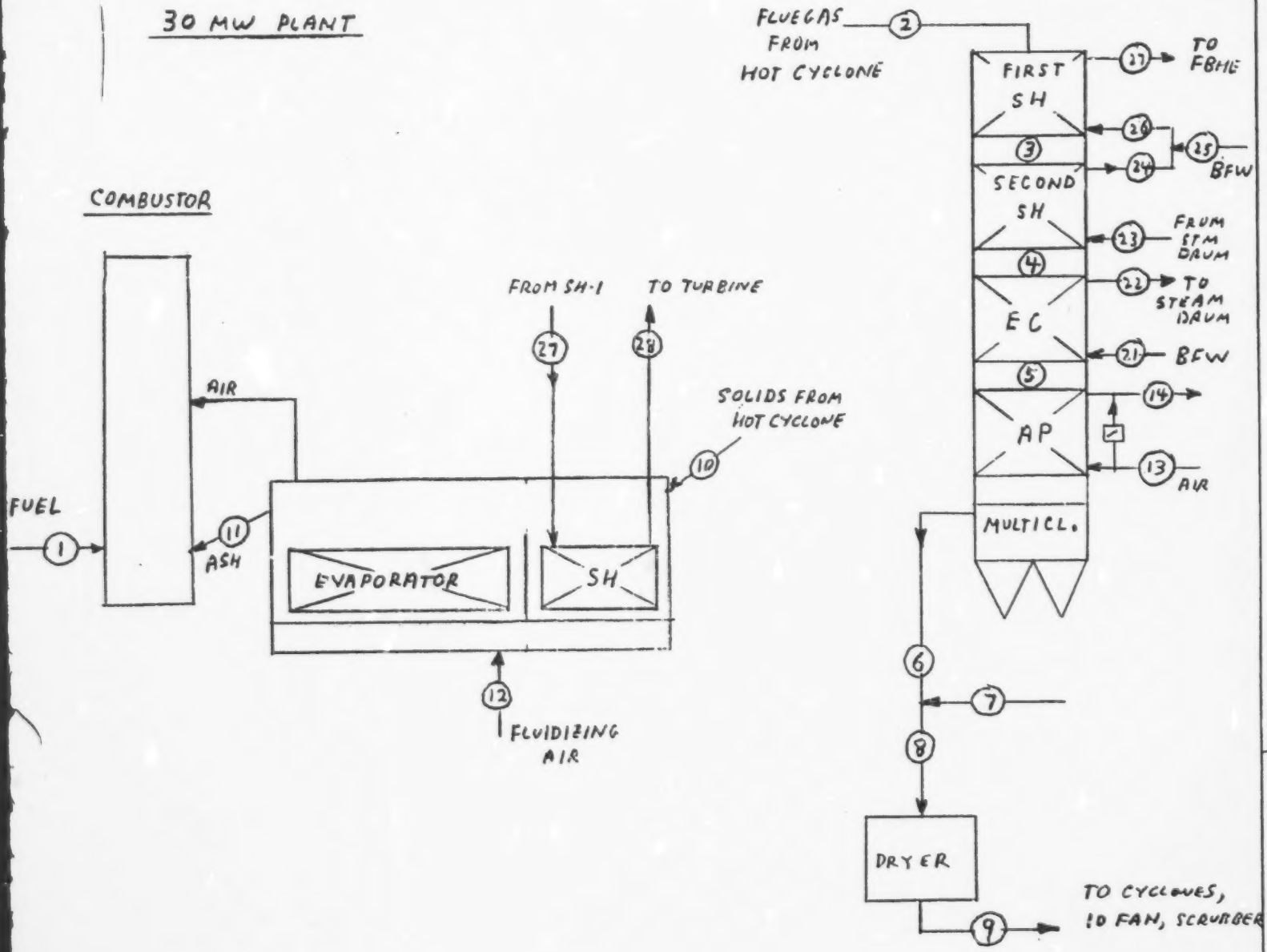
30 MW PLANT



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CALCULATION SHEET

SUBJECT: ALTERNATE III

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LURGI LURGI CORPORATION

CALCULATION SHEET

SUBJECT: ALTERNATE III

30 MW PLANT

DRYER LOAD: 600 TPH

DUTY, BTU/HR:

FBHE SUPERHEATER	26.2×10^6
FBHE EVAPORATOR	155.8×10^6
FIRST SUPERHEATER	20.0×10^6
SECOND SUPERHEATER	36.7×10^6
ECONOMIZER	102.9×10^6
AIR PREHEATER	27.9×10^6
DRYER	123.4×10^6

	FUEL	FLUEGAS FROM CYCL.	FLUEGAS FROM SH-1	FLUEGAS FROM SH-2	FLUEGAS FROM EC	FLUEGAS FROM AP	DILUTION AIR	TO DRYER
	1	2	3	4	5	6	7	8
LB/HR	200,722	752,637	752,637	752,637	752,637	752,637	0	752,637
DEG F	-	1600	1514	1353	889	759	-	759

	FROM DRYER	SOLIDS TO FBHE	SOLIDS FROM FBHE	FBHE FLUID. AIR	COMBUSTION AIR	HOT COMB. AIR		
	9	10	11	12	13	14		
LB/HR	824,637	976,643	976,643	81,935	562,839	562,829		
DEG F	160	1600	860	40	40	250		

	BOILER FEED WATER	BFW FROM ECONOMIZER	STEAM TO SH-2	STEAM FROM SH-2	BFW TO DESUPERHEATER	STEAM TO SH-1	STEAM FROM SH-1 TO FBHE	STEAM TO TURBINE
	21	22	23	24	25	26	27	28
LB/HR	269,182	269,182	263,798	263,798	10,294	274,092	274,092	274,092
DEG F	230	578	587	704	230	647	749	900

APPRD:

CHKD:

BY:

DATE 11/15/84

REV.

PAGE 8

REF. NO. OR JOB NO.

3/11-79

LURGI CORPORATION

CALCULATION SHEET

SUBJECT: ALTERNATE III

30 MW PLANT

DRYER LOAD: 200 TPH

DUTY, BTU/HR:

FBHE SUPERHEATER	26.9×10^6
FBHE EVAPORATOR	178.9×10^6
FIRST SUPERHEATER	16.6×10^6
SECOND SUPERHEATER	29.5×10^6
ECONOMIZER	89.9×10^6
AIR PREHEATER	78.3×10^6
DRYER	41.1×10^6

	FUEL 1	FLUEGAS FROM CYCL. 2	FLUEGAS FROM SH-1 3	FLUEGAS FROM SH-2 4	FLUEGAS FROM EC 5	FLUEGAS FROM AP 6	DILUTION AIR 7	TO DRYER 8
LB/HR	165,991	622,407	622,407	622,407	622,407	622,407	63,663	686,070
DEG F	–	1600	1513	1357	867	418	40	387

	FROM DRYER 9	SOLIDS TO FBHE 10	SOLIDS FROM FBHE 11	FBHE FLUID. AIR 12	COMBUSTION AIR 13	HOT COMB. AIR 14		
LB/HR	710,070	1,159,185	1,159,185	81,935	451,273	451,273		
DEG F	160	1600	900	40	40	747		

	BOILER FEED WATER 21	BFW FROM ECONOMIZER 22	STEAM TO SH-2 23	STEAM FROM SH-2 24	BFW TO DESUPERHEATER 25	STEAM TO SH-1 26	STEAM FROM SH-1 TO FBHE 27	STEAM TO TURBINE 28
LB/HR	279,686	279,686	274,092	274,092	0	274,092	274,092	274,092
DEG F	230	530	587	661	–	661	746	900

REF. NO. OR JOB NO.

DATE 11/15/84 REV.

BY:

CHKD:

APPRD:

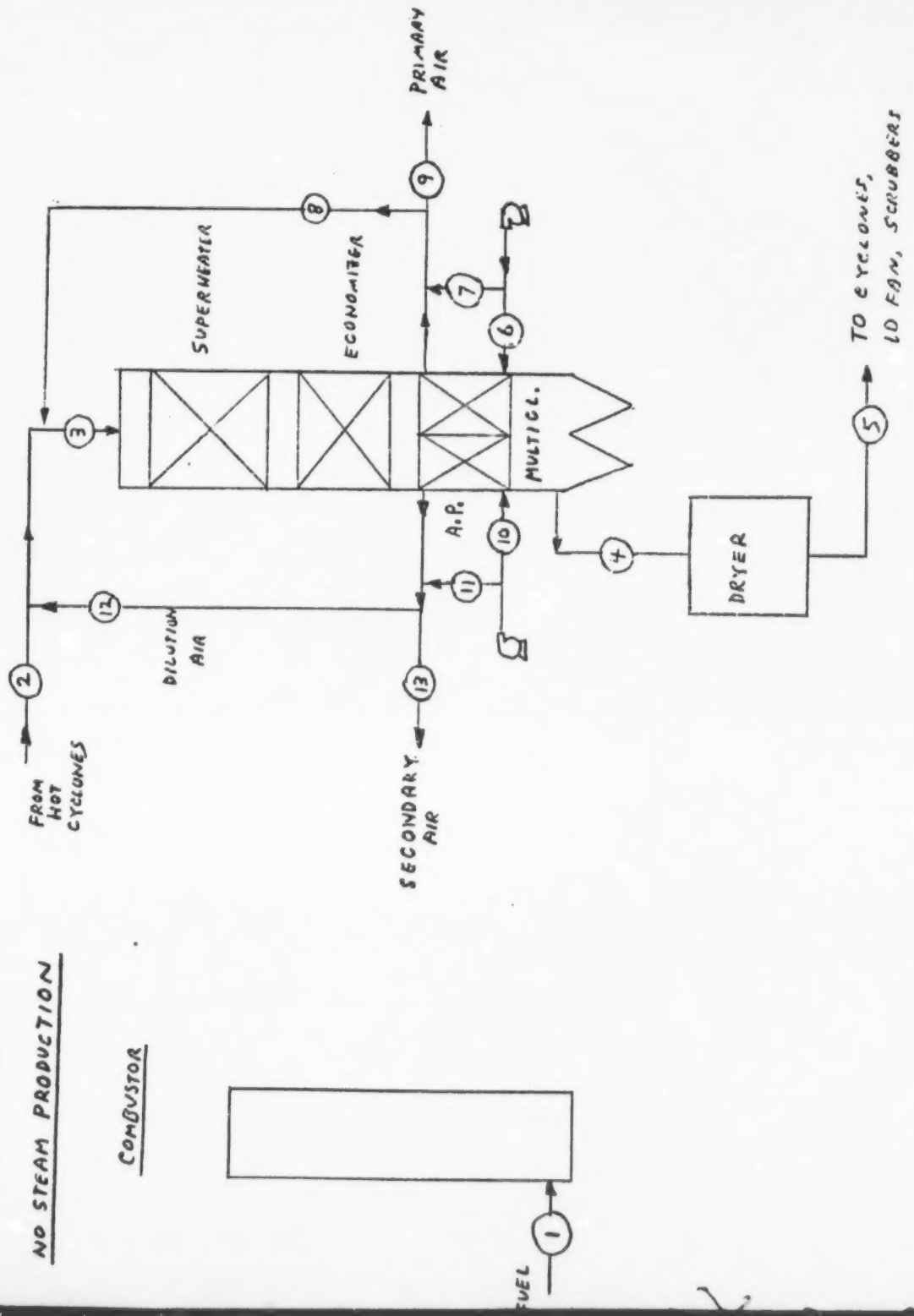
PAGE 7

LURGI LURGI CORPORATION

CALCULATION SHEET

REF. NO. OR JOB NO.		
DATE 1/18/85	REV.	PAGE 10
BY:		
CHKD:		
APPRD:		

SUBJECT: ALTERNATE III NO STEAM



3/11-79

DUTIES

FBHE SUPERHEATER 0
FBHE EVAPORATOR 0

CONV PASS
SUPERHEATER 0
ECONOMIZER 0
AIR PREHEATER 0

30 MW PLANT

NO STEAM PRODUCTION

DRYER LOAD 600 TPH

	FUEL	FLUEGAS FROM CYCLONE	FLUEGAS TO CONV. PASS	FLUEGAS TO DRYER	FLUEGAS FROM DRYER	PRIMARY AIR TO PREHEATER	PRIMARY AIR PREHTR. BYPASS
	1	2	3	4	5	6	7
LB/HR	62,243	329,633	638,640	638,640	710,640	0	257,910
DEG F	-	1600	905	905	160	-	40

	PRIMARY DILUTION AIR	PRIMARY AIR TO COMBUSTOR	SECONDARY AIR TO PREHEATER	SECONDARY AIR PREHTR. BYPASS	SECONDARY DILUTION AIR	SECONDARY AIR TO COMBUSTOR	
	8	9	10	11	12	13	
LB/HR	139,438	118,472	0	347,729	169,570	177,709	
DEG F	40	40	-	40	40	40	

LURGI LURGI CORPORATION

CALCULATION SHEET

SUBJECT: ALTERNATE III NO STEAM

REF. NO. OR JOB NO.

DATE 11/18/85 REV. PAGE 11

BY:

CHKD:

APPRD:

8/11-79

LURGI CORPORATION

CALCULATION SHEET

SUBJECT: ALTERNATE III NO STEAM

REF. NO. OR JOB NO.

DATE 1/16/85 REV. PAGE 12

BY:

CHKD:

APPRD:

30 MW PLANT

NO STEAM PRODUCTION

DRYER LOAD 200 TPH

DUTIES

FBHE SUPERHEATER 0

FBHE EVAPORATOR 0

CONV PASS

SUPERHEATER 0

ECONOMIZER 0

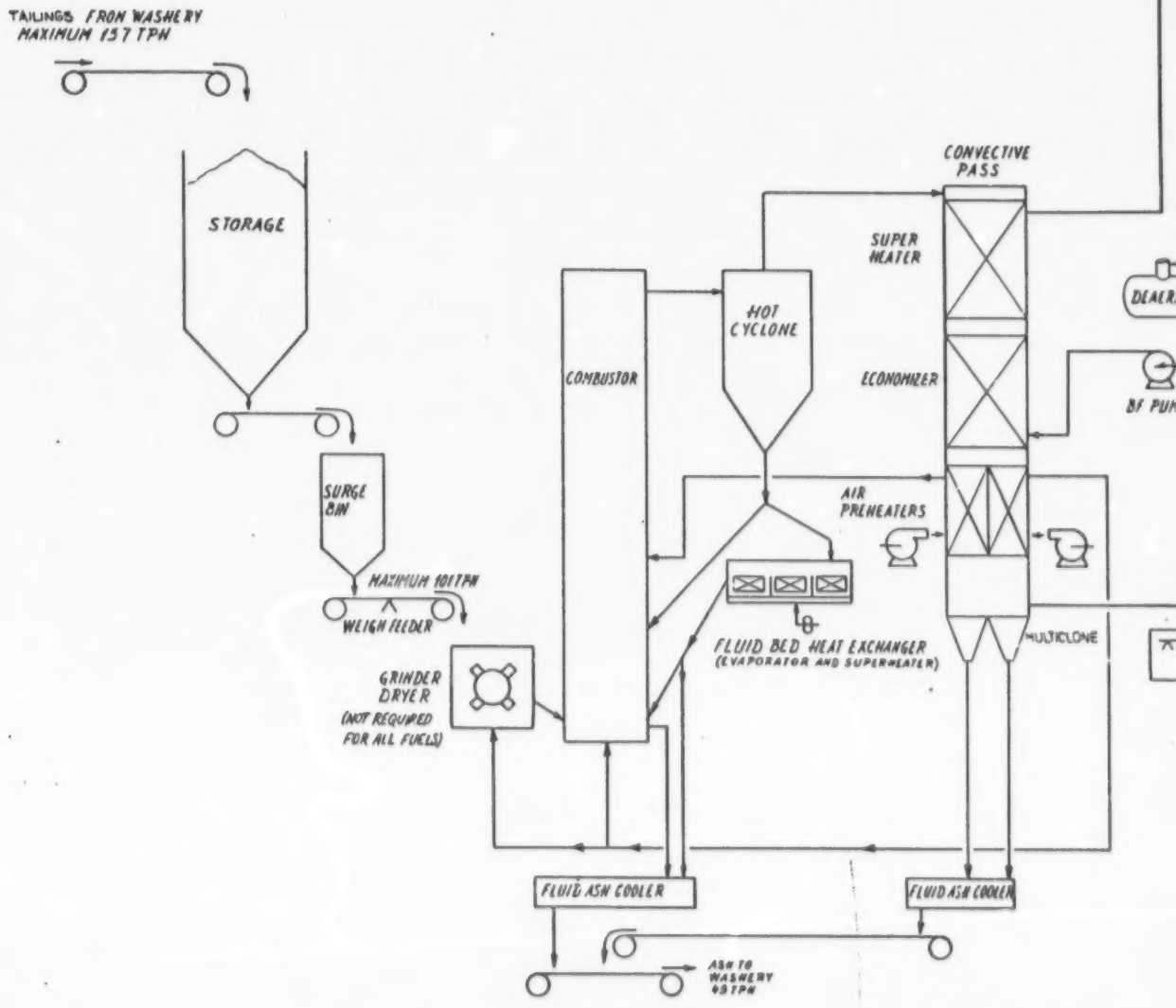
AIR PREHEATER 0

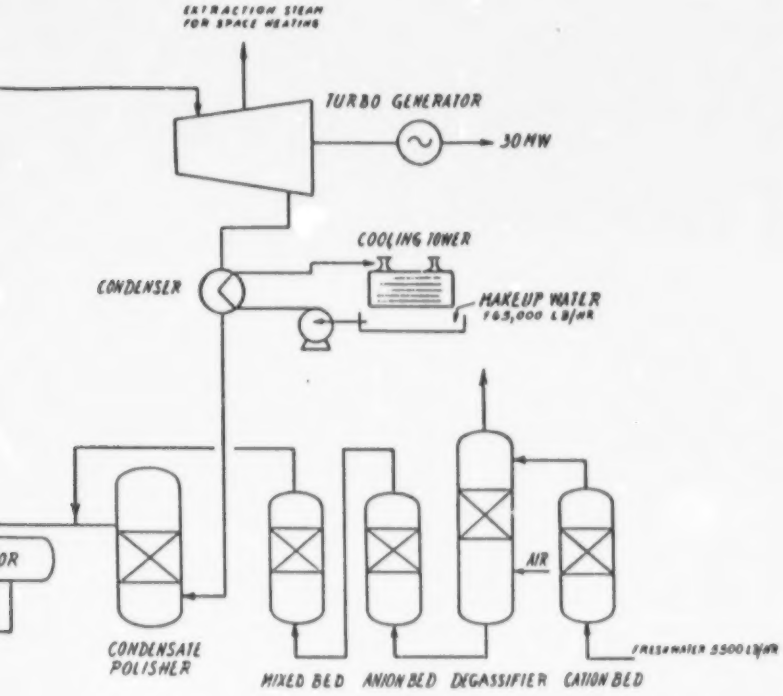
	FUEL	FLUEGAS FROM CYCLONE	FLUEGAS TO CONV. PASS	FLUEGAS TO DRYER	FLUEGAS FROM DRYER	PRIMARY AIR TO PREHEATER	PRIMARY AIR PREHTR. BYPASS
	1	2	3	4	5	6	7
LB/HR	28,393	140,121	686,640	686,640	710,640	0	307,649
DEG F	-	1600	403	403	160	-	40

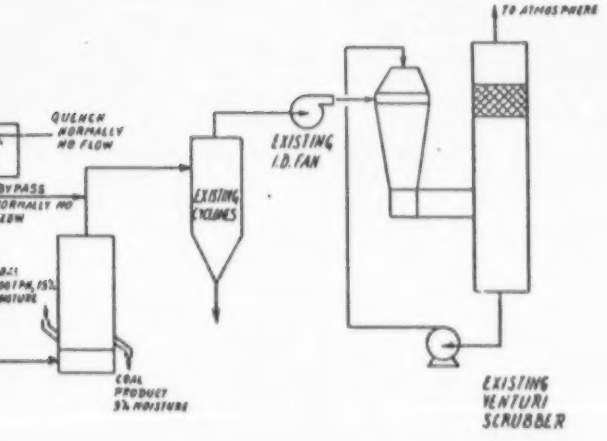
	PRIMARY DILUTION AIR	PRIMARY AIR TO COMBUSTOR	SECONDARY AIR TO PREHEATER	SECONDARY AIR PREHTR. BYPASS	SECONDARY DILUTION AIR	SECONDARY AIR TO COMBUSTOR	
	8	9	10	11	12	13	
LB/HR	182,783	124,866	0	363,736	363,736	0	
DEG F	40	40	-	40	40	-	

LURGI

DRAWINGS


TAILINGS FROM WASHERY
MAXIMUM 157 TPH
STORAGE
SURGE BIN
MAXIMUM 101 TPH
WEIGH FEEDER
GRINDER DRYER
(NOT REQUIRED FOR ALL FUELS)
COMBUSTOR
HOT CYCLONE
CONVECTIVE PASS
SUPER HEATER
ECONOMIZER
AIR PREHEATERS
FLUID BED HEAT EXCHANGER
(EVAPORATOR AND SUPERHEATER)
MULTICLONE
FLUID ASH COOLER
FLUID ASH COOLER
ASH TO WASHERY
45 TPH





No.	DATE	REVISION	BY	APP'D	CONSULTING
B	6/11/96	UPDATED	BM	MS	
A	11/18/95	PRELIMINARY	FB		

LURGI

LURGI CANADA LTD.
TORONTO, ONTARIO

DRAWN DATE	CHECKED DATE	DESIGN APPROVED	CHIEF ENGR.	CLIENT APPROVED
FB 11/9/95				

CLIENT DWG. No. | REV.

PROJECT TITLE
WASTE COAL UTILIZATION STUDY

DRAWING TITLE
OVERALL PROCESS SCHEMATIC

LURGI DWG. No. P-62504-11 | REV. B

PROJECT No. | SCALE: NONE

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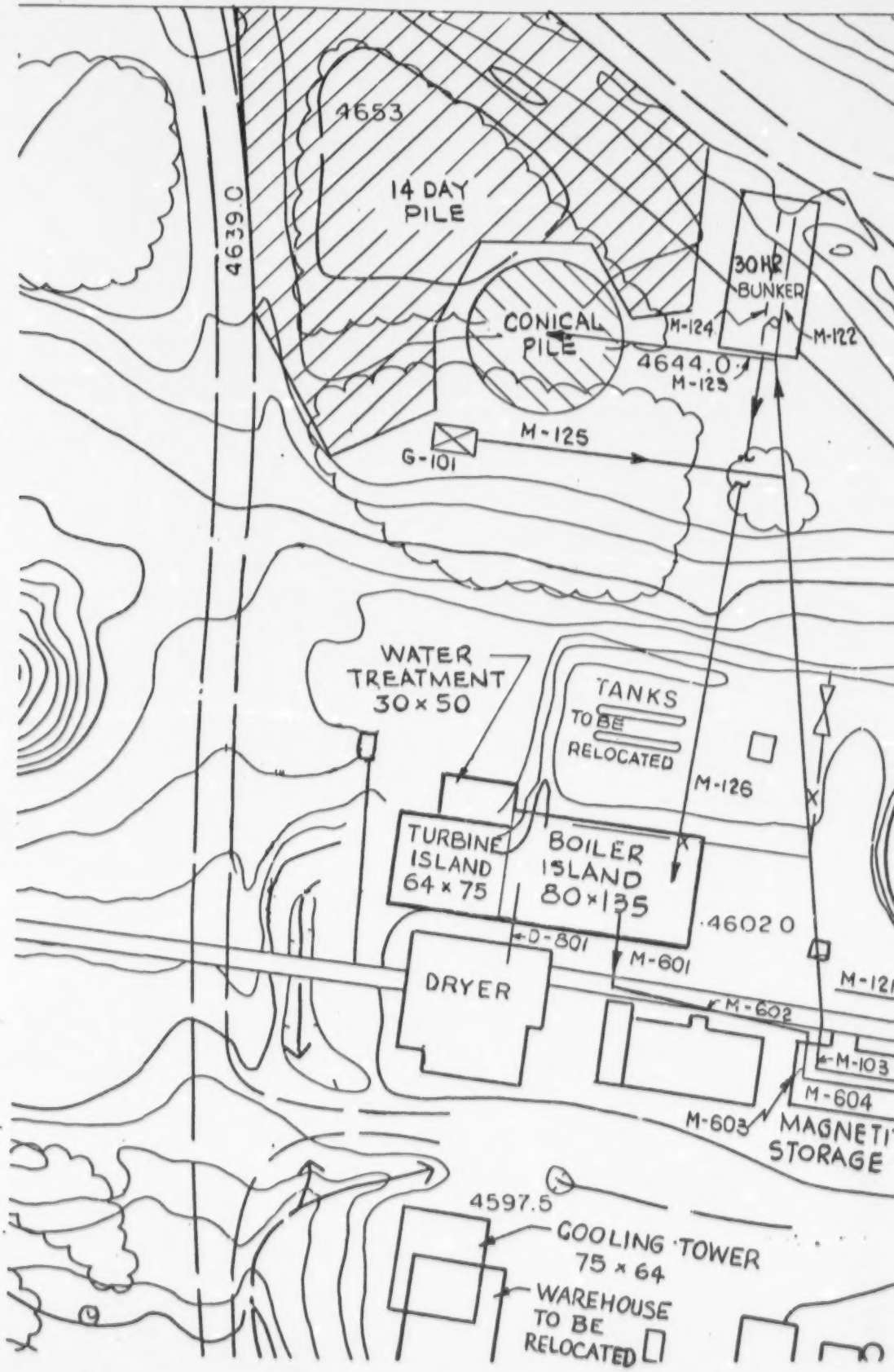

4653
14 DAY PILE
4639.0
CONICAL PILE
30 HR BUNKER
M-124
M-122
4644.0
M-123
M-125
G-101
WATER TREATMENT 30 × 50
TANKS TO BE RELOCATED
M-126
TURBINE ISLAND 64 × 75
BOILER ISLAND 80 × 135
4602.0
D-801
M-601
DRYER
M-602
M-103
M-604
M-603
MAGNETI
STORAGE
4597.5
COOLING TOWER 75 × 64
WAREHOUSE TO BE RELOCATED

THIS DRAWING IS THE PROPERTY OF LURGI CORPORATION AND IS SUBJECT TO RETURN ON DEMAND IT CONTAINS TRADE SECRETS OF THE CORPORATION ITS CONTENTS ARE DISCLOSED IN CONFIDENCE TO AUTHORIZED PERSONS ONLY DISCLOSURE OF INFORMATION HEREIN EMBODIED IS PROHIBITED EXCEPT AS EXPRESSLY AUTHORIZED BY THE CORPORATION NOT INTENDED FOR PUBLICATION COPYING IN WHOLE OR PART PROHIBITED

no.	DATE	REVISION	BY	APP'D	CONSTR ISSUE
A	01/25/05	PRELIMINARY	JF	MD	

LURGI

LURGI CANADA LTD.
TORONTO, ONTARIO

DRAWN DATE	CHECKED DATE	DESIGN APPROVED	CHIEF ENGR.	CLIENT APPROVED
JF 1/18/05				

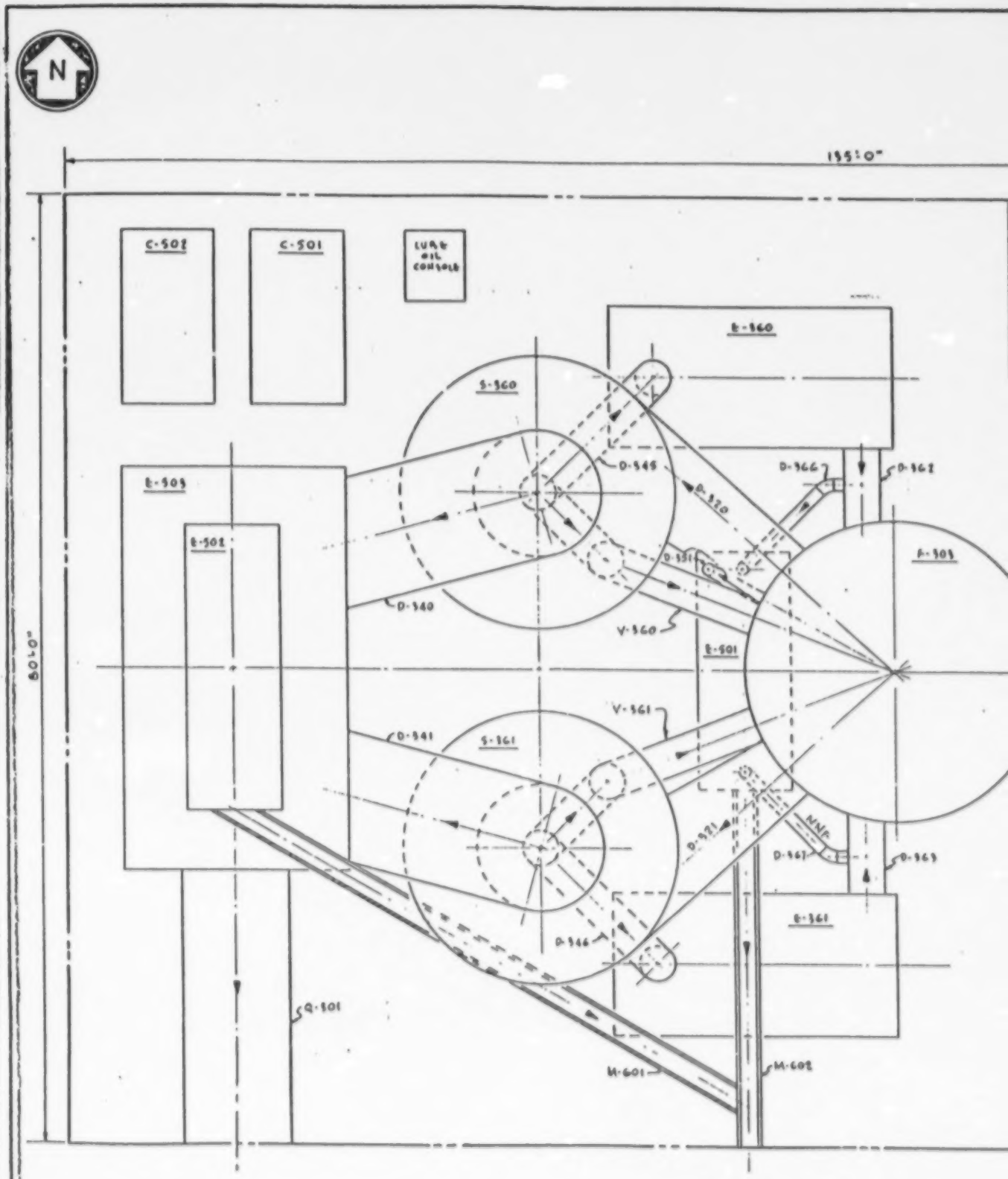
CLIENT DWG. No. | REV.

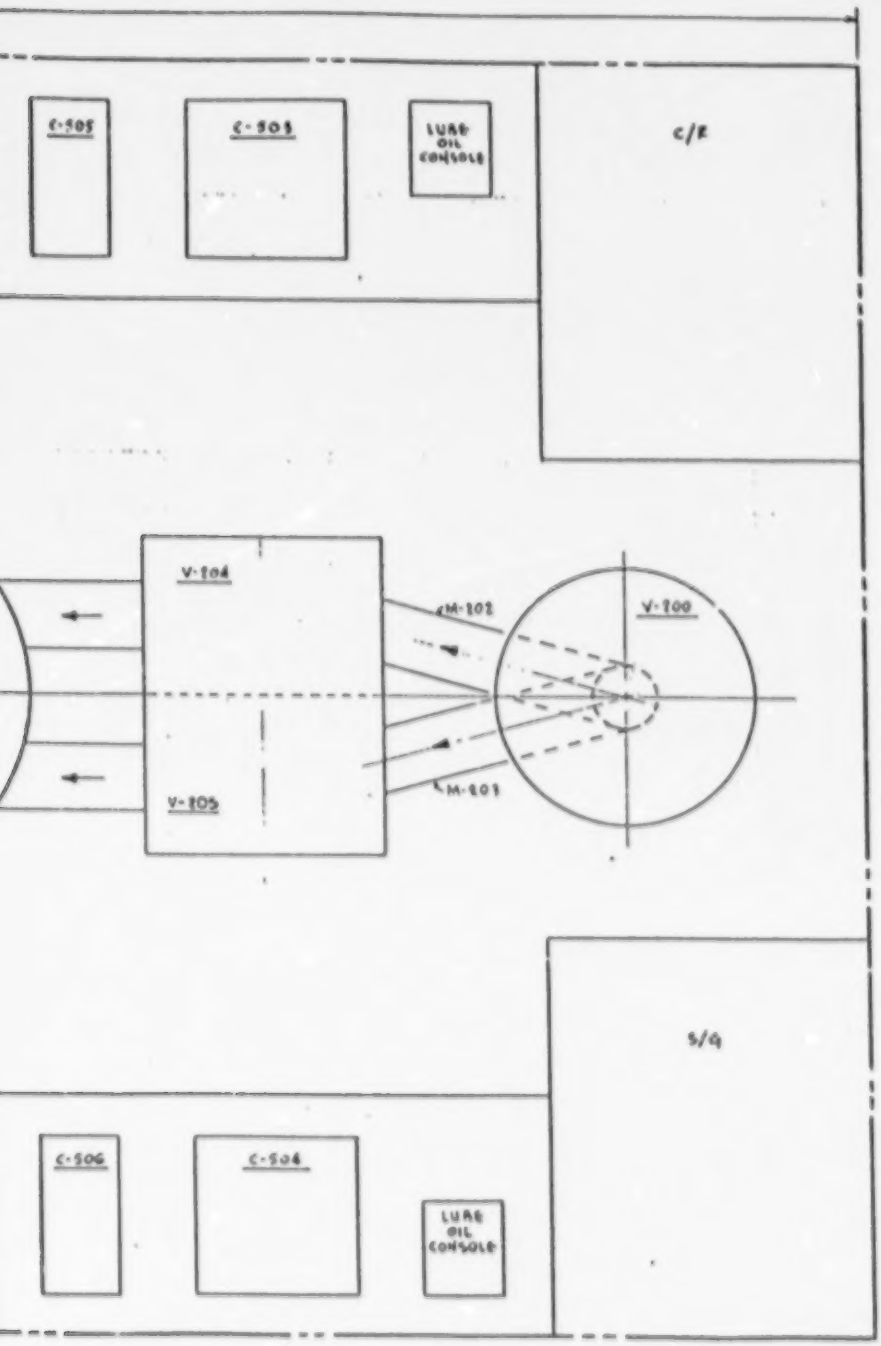
PROJECT TITLE
WASTE COAL UTILIZATION STUDY

DRAWING TITLE
PLOT PLAN

LURGI DWG. No. P-62504-10 | REV. A

PROJECT No. | SCALE:


N
195'-0"
80'-0"
C-502
C-501
LUBE OIL CONSOLE
E-360
S-360
D-345
D-346
D-342
D-340
V-360
E-303
E-302
A-303
E-301
V-361
D-341
S-361
D-321
NNF
D-343
E-361
D-346
Q-301
M-601
M-602



C/R	CONTROL ROOM
S/G	SWITCHGEAR ROOM
C-501	PRIMARY AIR FAN
C-502	SECONDARY AIR FAN
C-503/C-504	FBHE BLOWERS
C-505/C-506	SEAL POT BLOWERS
D-320/D-321	HOT GAS DUCTS
D-340/D-341	HOT GAS DUCTS
D-345/D-346	HOT SOLIDS DUCTS
D-361	ASH DRAIN
D-362/D-363	HOT SOLIDS DUCTS
D-364/D-367	ASH DRAIN
E-501	FBHE ASH COOLER
E-502	MULTICLONE ASH COOLER
E-503	BACKPASS WITH MULTICLONE
E-360/E-361	FLUID BED HEAT EXCHANGERS
F-303	COMBUSTOR VESSEL
M-702/M-703	FUEL WEIGH FEEDERS
M-601	ASH CONVEYOR
M-602	ASH CONVEYOR
D-301	FLUEGAS D CT
S-360/S-361	HOT CYCLONES
V-700	COAL FEED BIN
V-704/V-705	FUEL CRUSHER/DRYER
V-360/V-361	CYCLONE SEAL POTS

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No	DATE	REVISION	BY	CHKD	ENGR
A	1/29/84	PRELIMINARY	HLA	HB	

LURGI

LURGI CANADA LTD.
TORONTO, ONTARIO

DRAWN DATE	CHECKED DATE	DESIGN APPROVED	CHIEF ENGR	CLIENT APPROVED

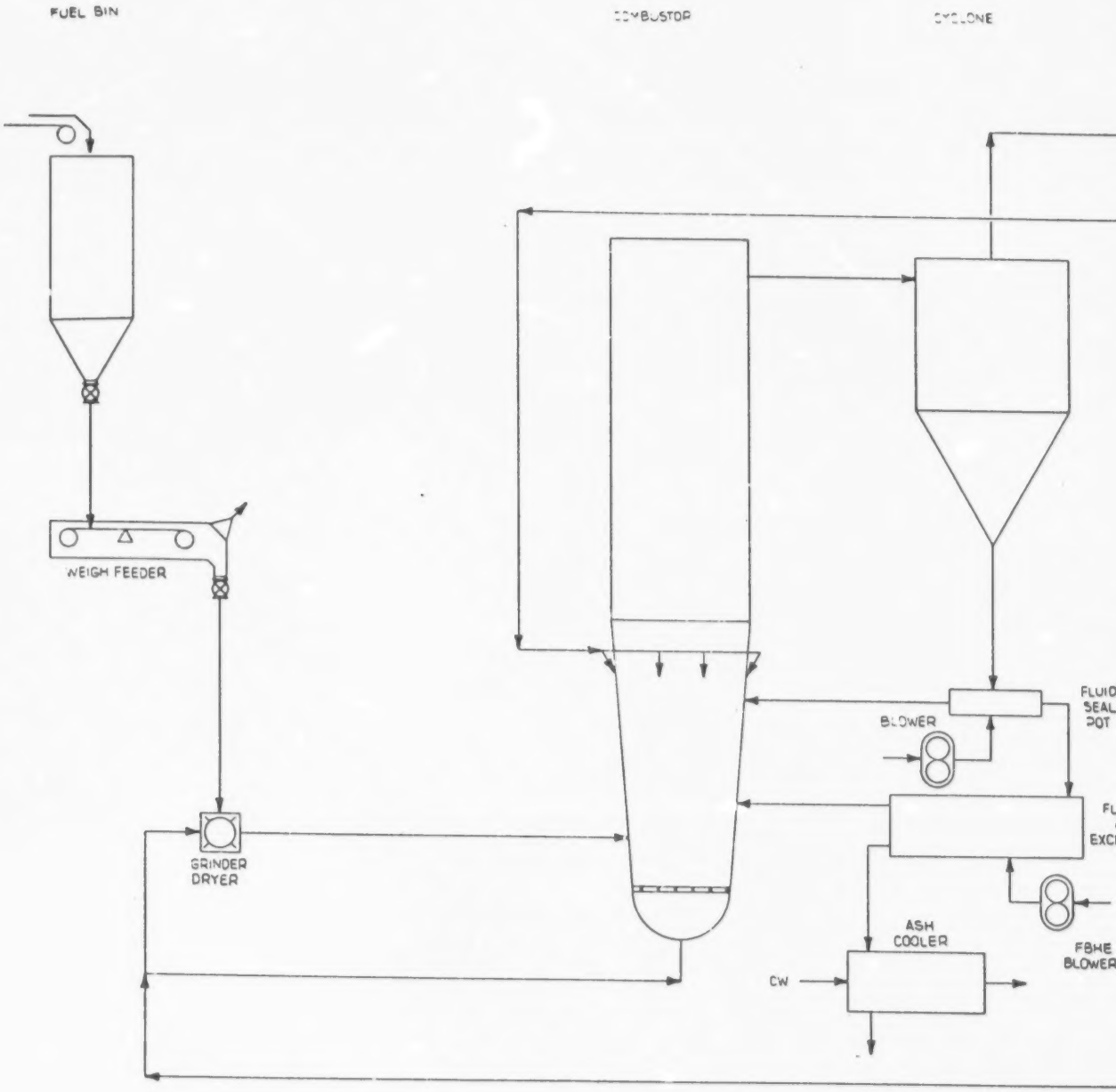
CLIENT DWG. No. | REV.

PROJECT TITLE
LUSCAR
COAL TAILINGS UTILIZATION STUDY
COAL VALLEY ALBERTA

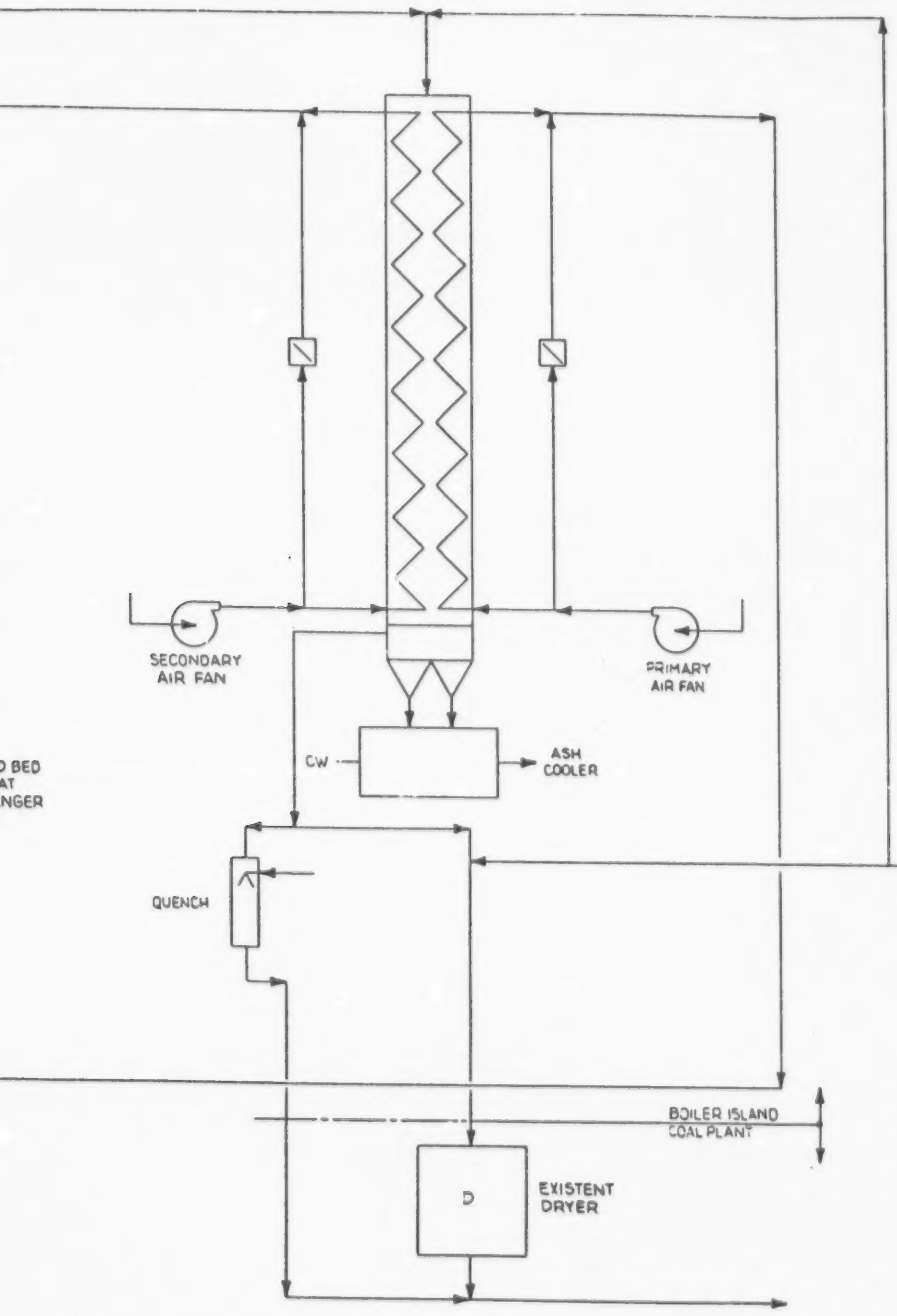
DRAWING TITLE
CONCEPTUAL PLAN OF CFB BOILER ISLAND

LURGI DWG. No. 62904-00-D-90-001 | REV A

PROJECT No 62904 | SCALE 3/16" = 1'-0"


FUEL BIN
COMBUSTOR
CYCLONE
WEIGH FEEDER
GRINDER
DRYER
BLOWER
ASH
COOLER
CW

PRIMARY AND SECONDARY
COMBUSTION AIR PREHEATER
WITH MULTICLONE



REV	DATE	DESCRIPTION	DWN	APPD
2	07/12/82	UPDATED	EM	WB
1	06/04	PRELIMINARY	EM	

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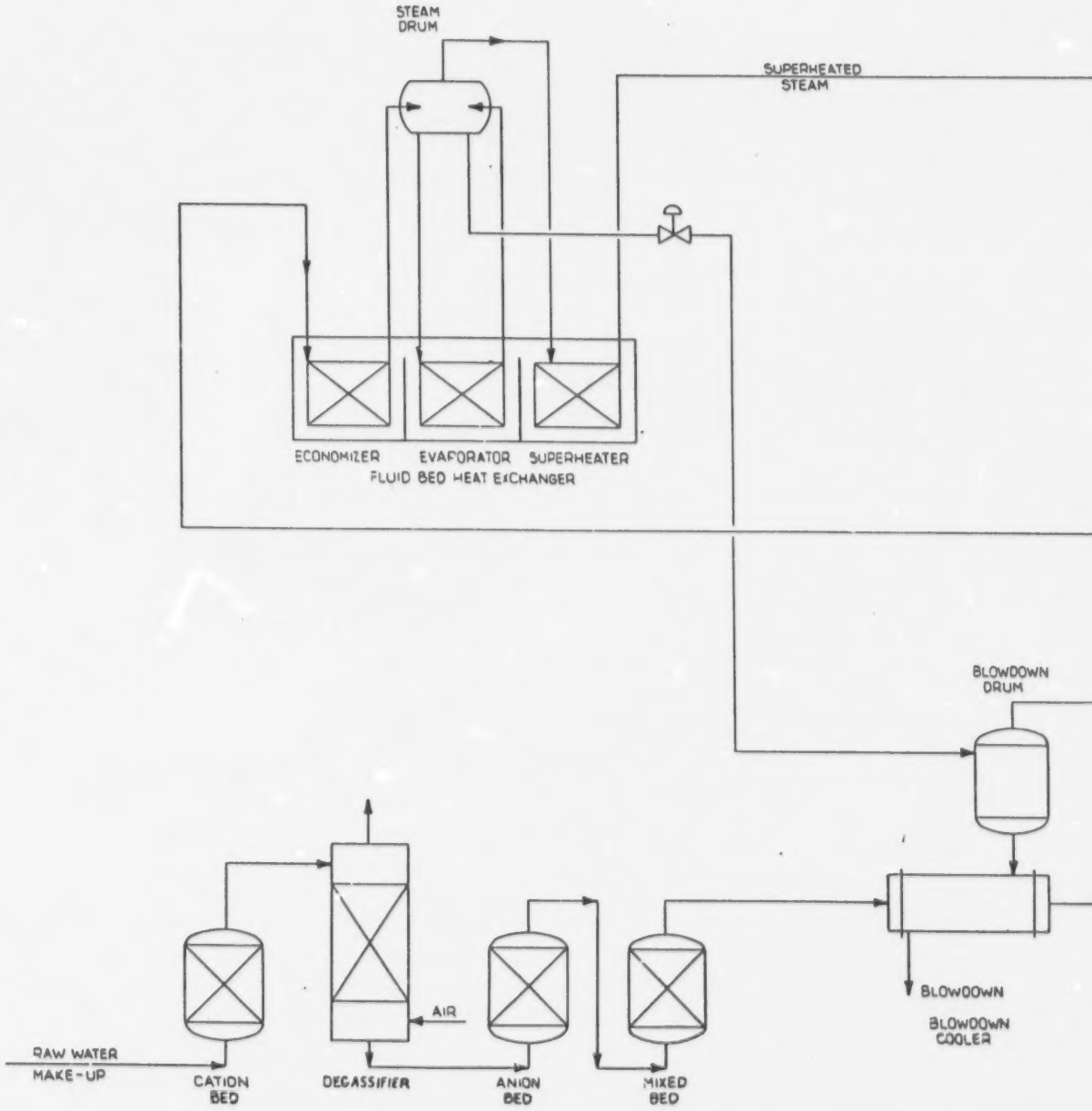
LURGI CORPORATION
RIVER EDGE, NEW JERSEY.

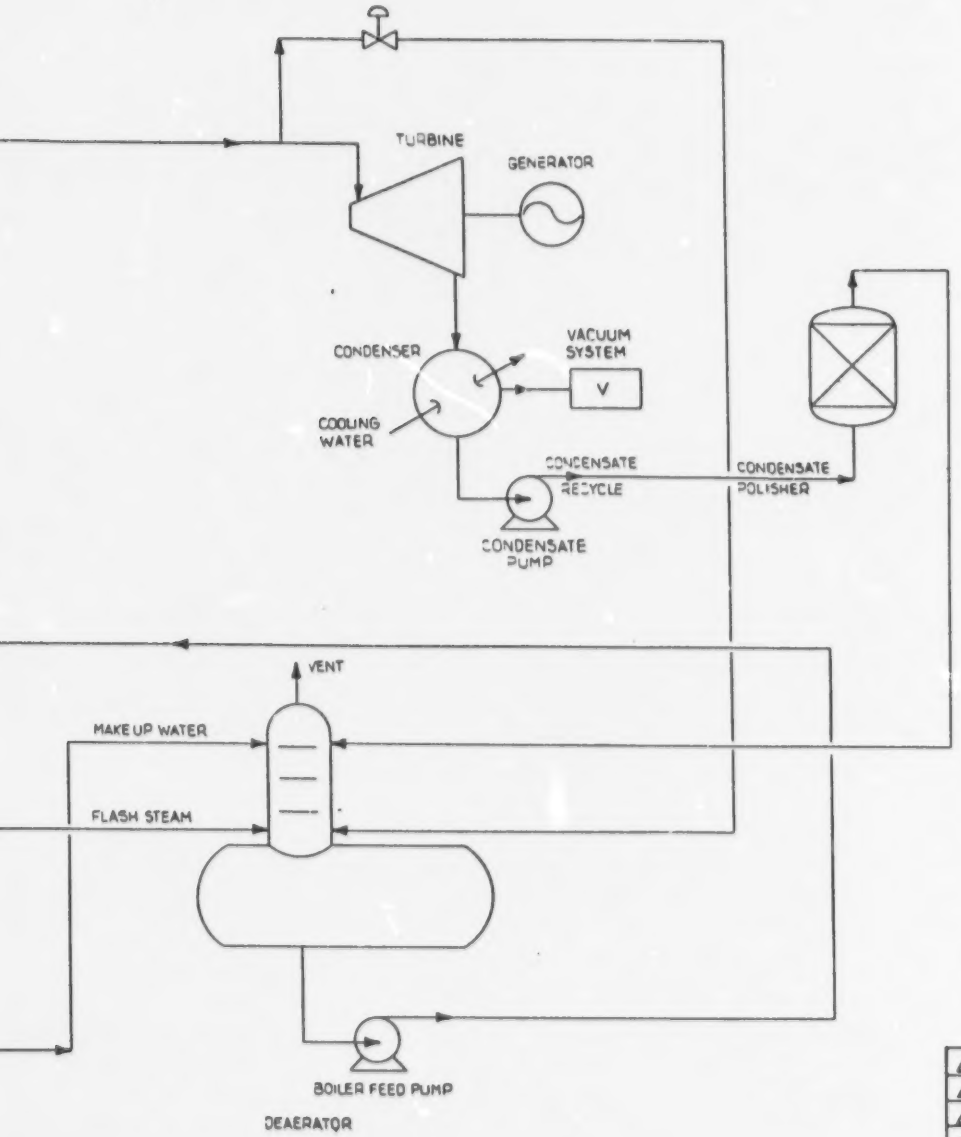
CLIENT: LUSCAR
PROJECT: WASTE COAL UTILIZATION STUDY
LOCATION: COAL VALLEY, ALBERTA
PROJECT NO: 62504

DRAWING TITLE

PROCESS FLOW DIAGRAM
CFB COMBUSTOR FOR
A 10 MW PLANT

SCALE	DRAWING NUMBER	REV.
~NTS	D-62504-5	B


STEAM DRUM
SUPERHEATED STEAM
ECONOMIZER
EVAPORATOR
SUPERHEATER
FLUID BED HEAT EXCHANGER
BLOWDOWN DRUM
BLOWDOWN
BLOWDOWN COOLER
AIR
RAW WATER MAKE-UP
CATION BED
DEGASSIFIER
ANION BED
MIXED BED



REV	DATE	DESCRIPTION	DWN	APPD
3				
2	7/12/82	UPDATED	EM	HB
1	7/6/82	PRELIMINARY	EM	

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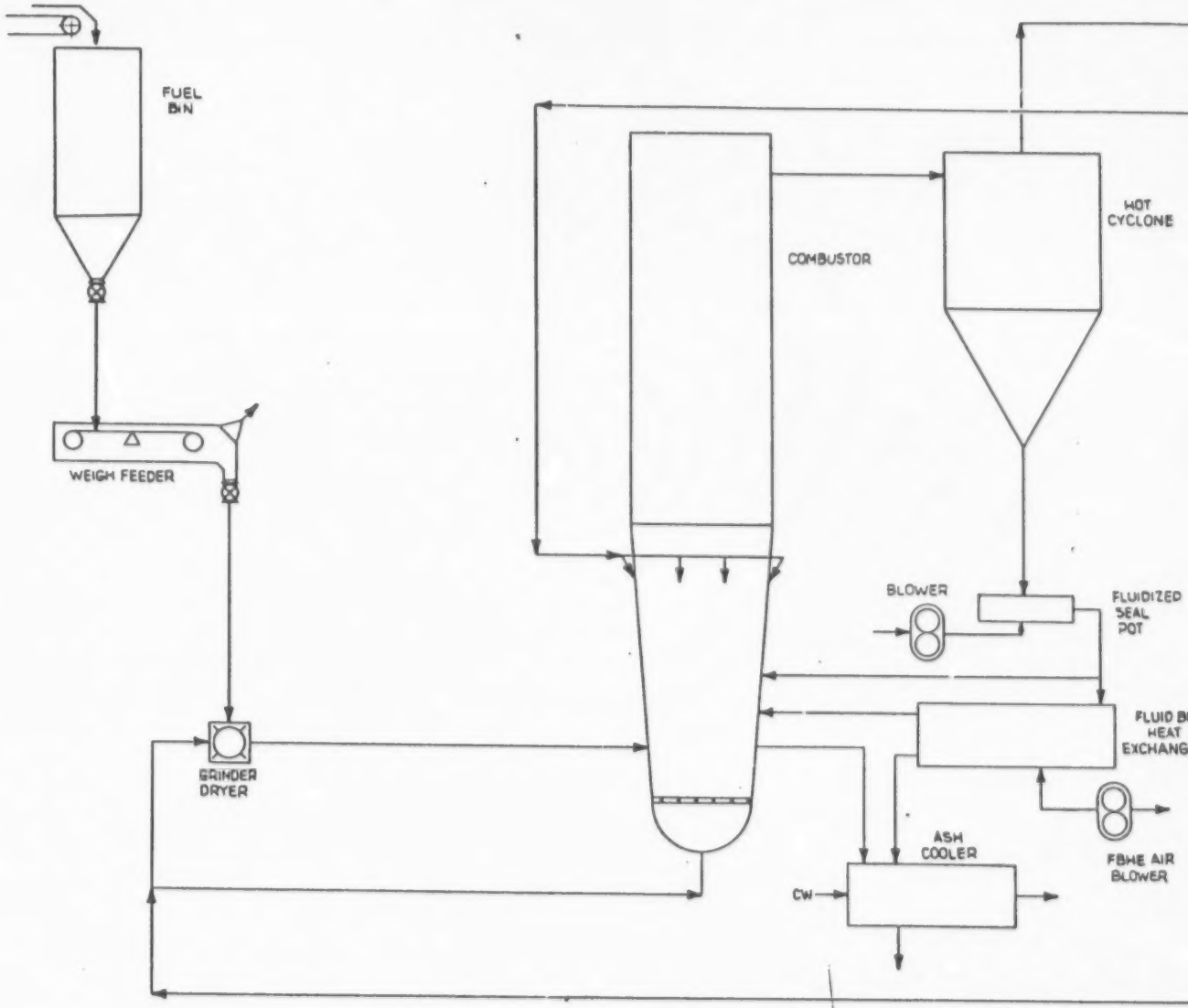
LURGI CORPORATION
RIVER EDGE, NEW JERSEY.

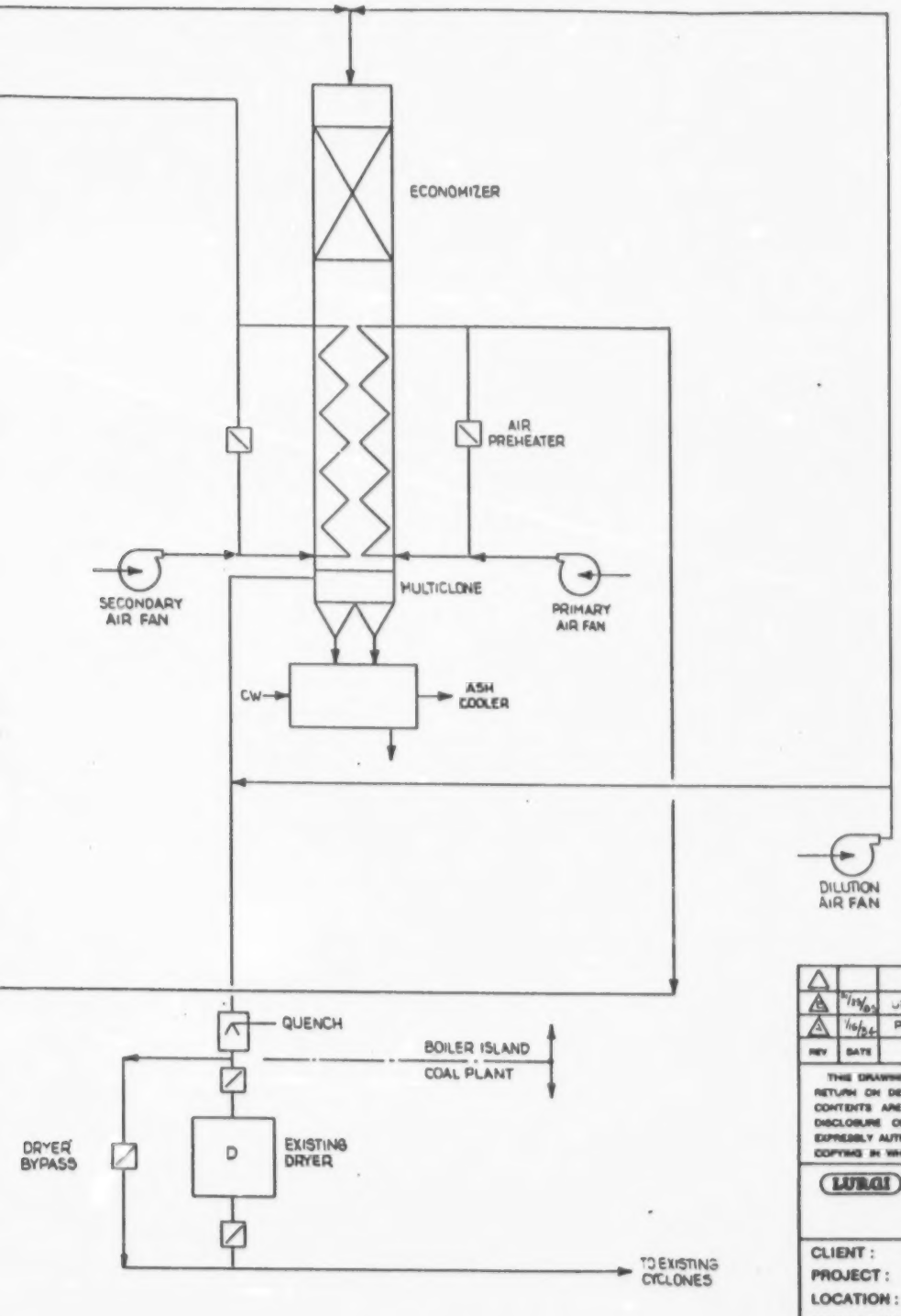
CLIENT: LUSCAR
PROJECT: WASTE COAL UTILIZATION STUDY
LOCATION: COAL VALLEY, ALBERTA
PROJECT NO: 62504

DRAWING TITLE

PROCESS FLOW DIAGRAM STEAM AND POWER GENERATION FOR 10 MW PLANT

SCALE	DRAWING NUMBER	REV.
~	P-62504-1	B


FUEL BIN
WEIGH FEEDER
GRINDER DRYER
COMBUSTOR
HOT CYCLONE
BLOWER
FLUIDIZED SEAL POT
FLUID B
HEAT EXCHANG
FBHE AIR BLOWER
ASH COOLER
CW



REV	DATE	DESCRIPTION	DWN	APPD
3				
2	12/19/84	UPDATED	BM	HB
1	11/6/84	PRELIMINARY	EM	

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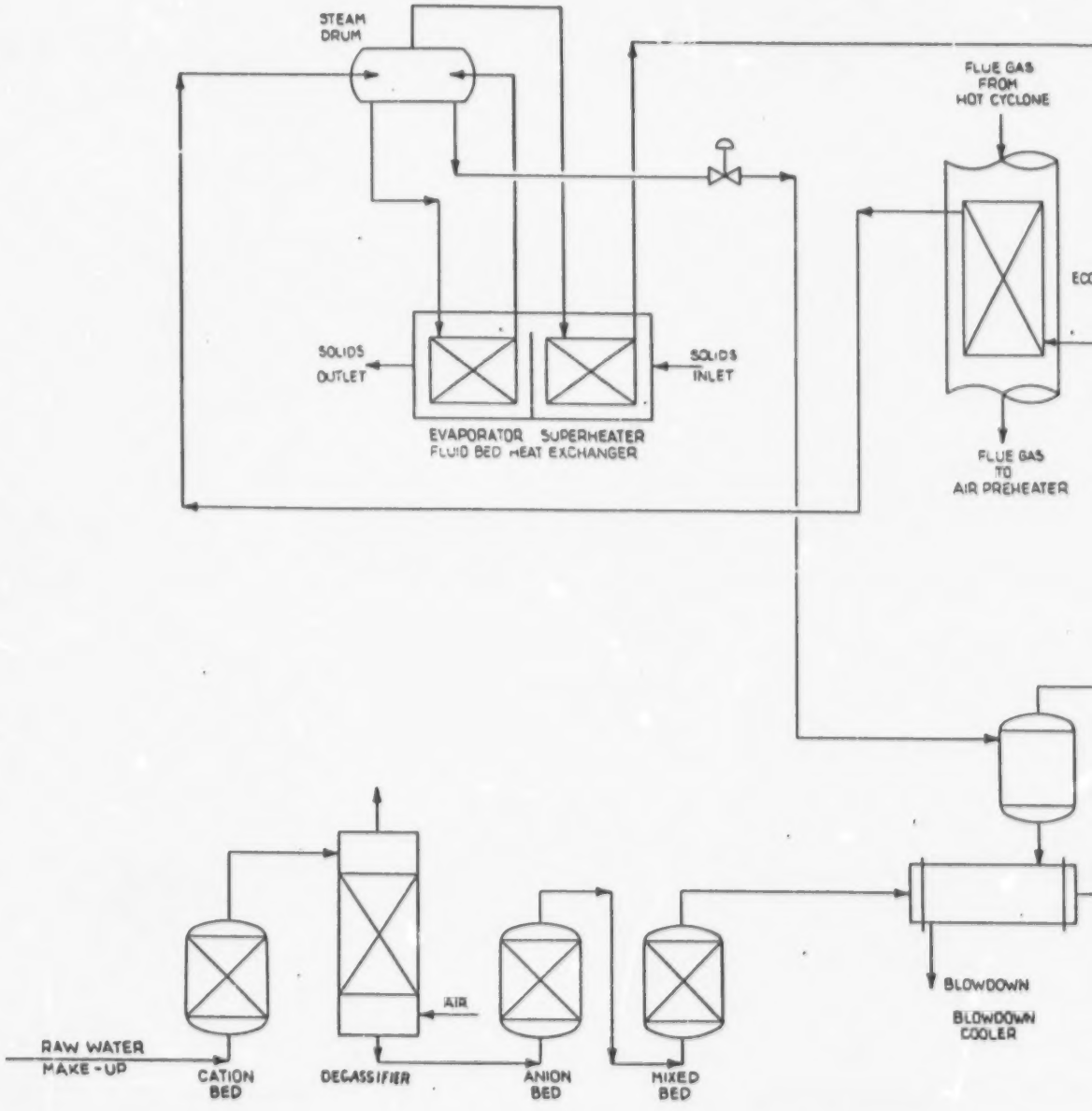
LURGI CORPORATION
RIVER EDGE, NEW JERSEY.

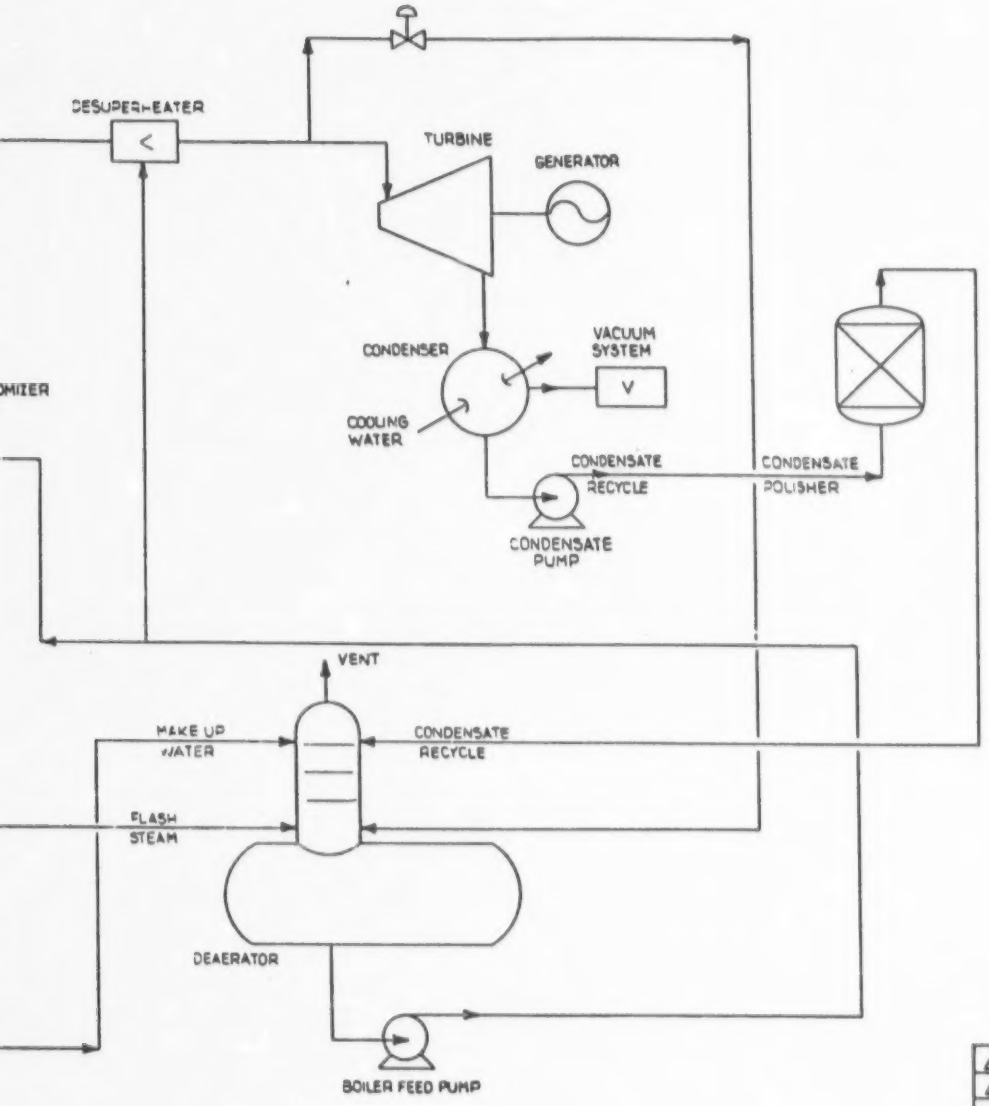
CLIENT : LUSCAR
PROJECT : WASTE COAL UTILIZATION STUDY
LOCATION : COAL VALLEY, ALBERTA
PROJECT NO : 62504

DRAWING TITLE

PROCESS FLOW DIAGRAM
CFB COMBUSTOR FOR
A 20 MW PLANT

SCALE	DRAWING NUMBER	REV.
NTS	P-62504-6	B


STEAM
DRUM
FLUE GAS
FROM
HOT CYCLONE
SOLIDS
OUTLET
SOLIDS
INLET
EVAPORATOR SUPERHEATER
FLUID BED HEAT EXCHANGER
FLUE GAS
TO
AIR PREHEATER
BLOWDOWN
BLOWDOWN
COOLER
AIR
RAW WATER
MAKE-UP
CATION
BED
DEGASSIFIER
ANION
BED
MIXED
BED



REV	DATE	DESCRIPTION	DWN	APP'D
2	9/11/93	UPDATED	E.M	MB
1	4/11/91	PRELIMINARY	E.M	

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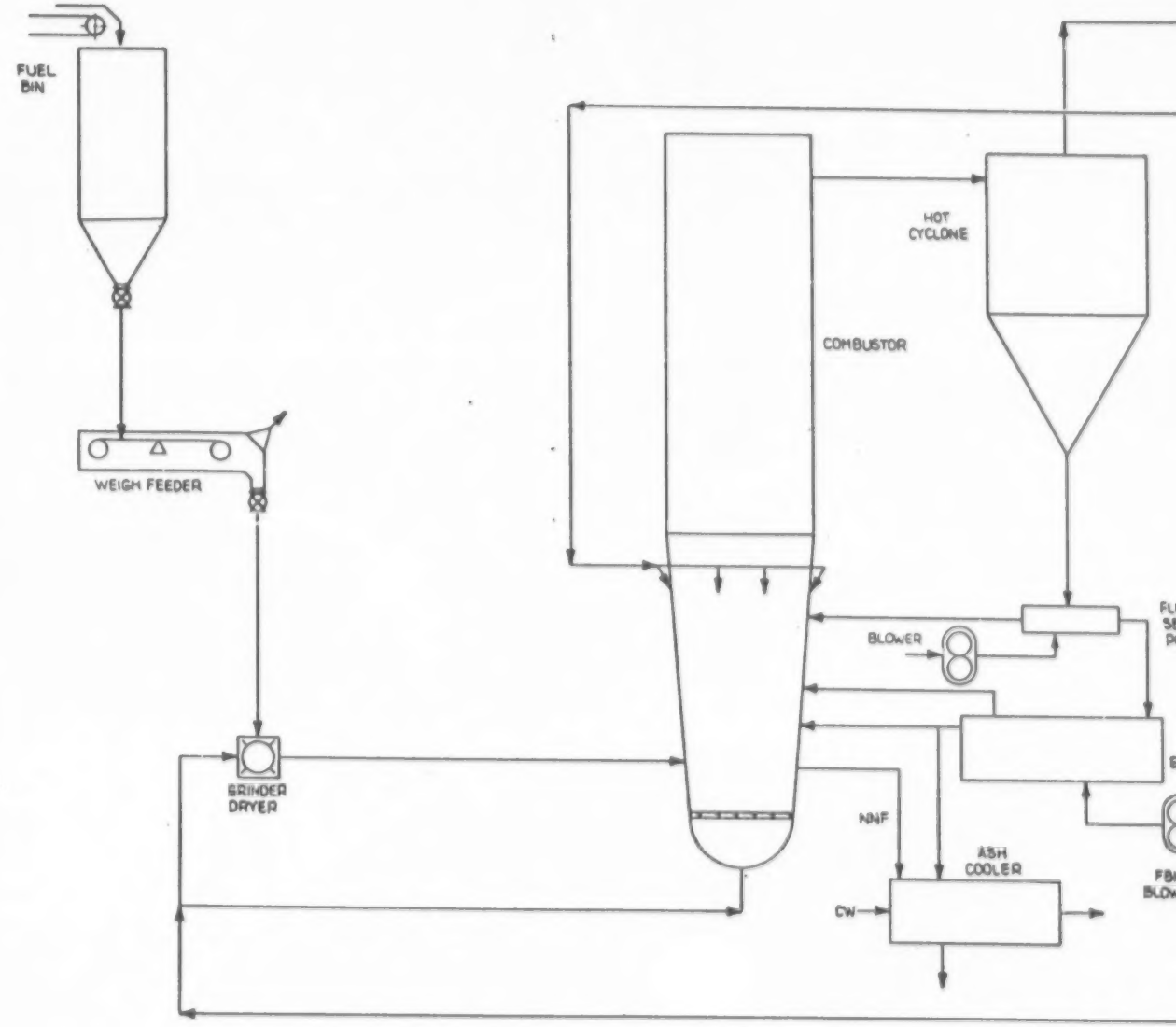
LURGI CORPORATION
RIVER EDGE, NEW JERSEY.

CLIENT: LUSCAR
PROJECT: WASTE COAL UTILIZATION STUDY
LOCATION: COAL VALLEY, ALBERTA
PROJECT NO: 62504

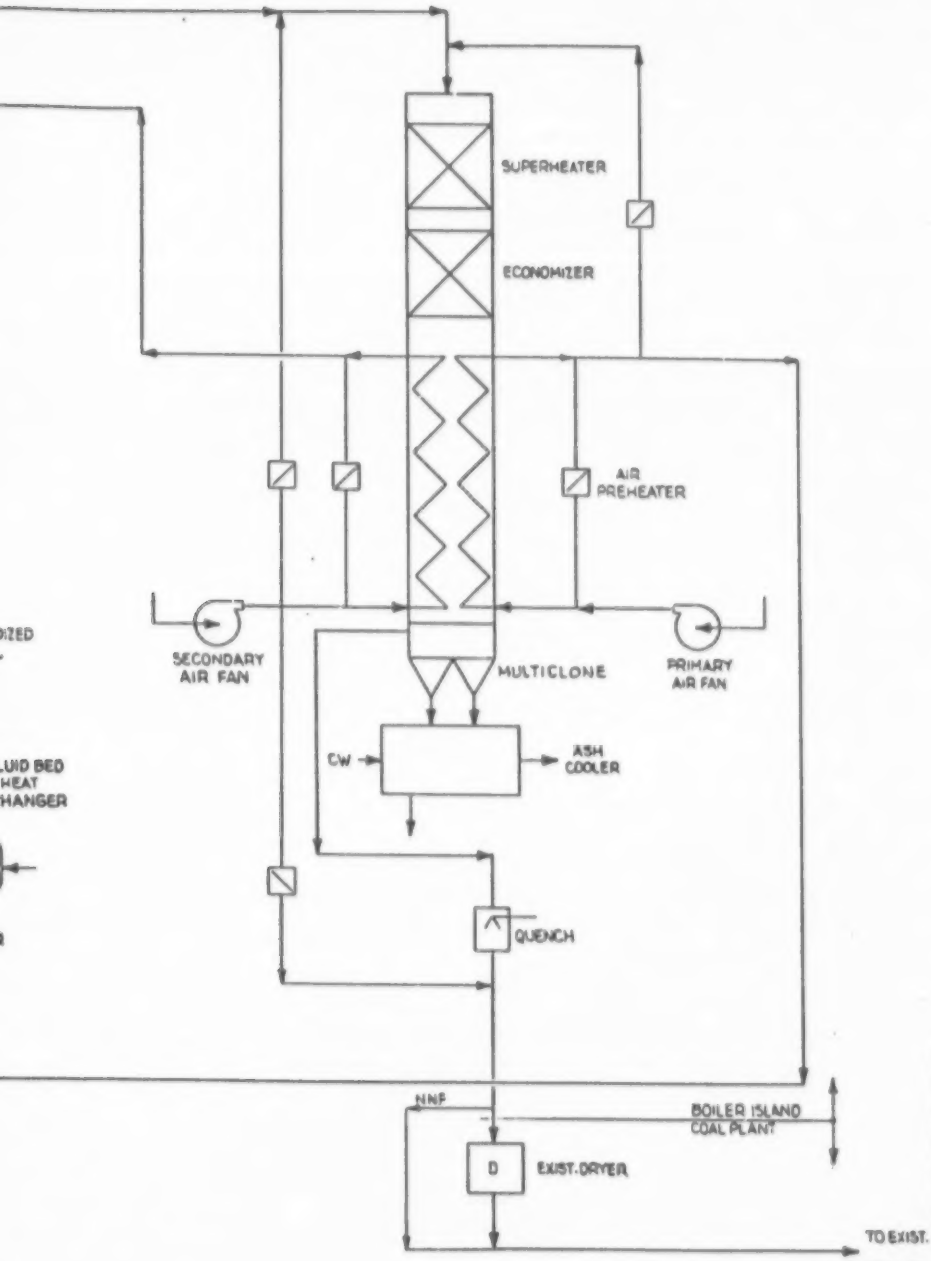
DRAWING TITLE

PROCESS FLOW DIAGRAM STEAM AND POWER GENERATION FOR 20 MW PLANT

SCALE	DRAWING NUMBER	REV.
~	P-62504-2	B


FUEL
BIN
WEIGH FEEDER
GRINDER
DRYER
COMBUSTOR
HOT
CYCLONE
BLOWER
NNF
ASH
COOLER
CW

PRIMARY AND SECONDARY
COMBUSTION AIR PREHEATER
WITH MULTICLONE



REV	DATE	DESCRIPTION	DRAWN	APPD
2	1/15/85	UPDATED	JF	HS
1	10/5/84	PRELIMINARY	EM	

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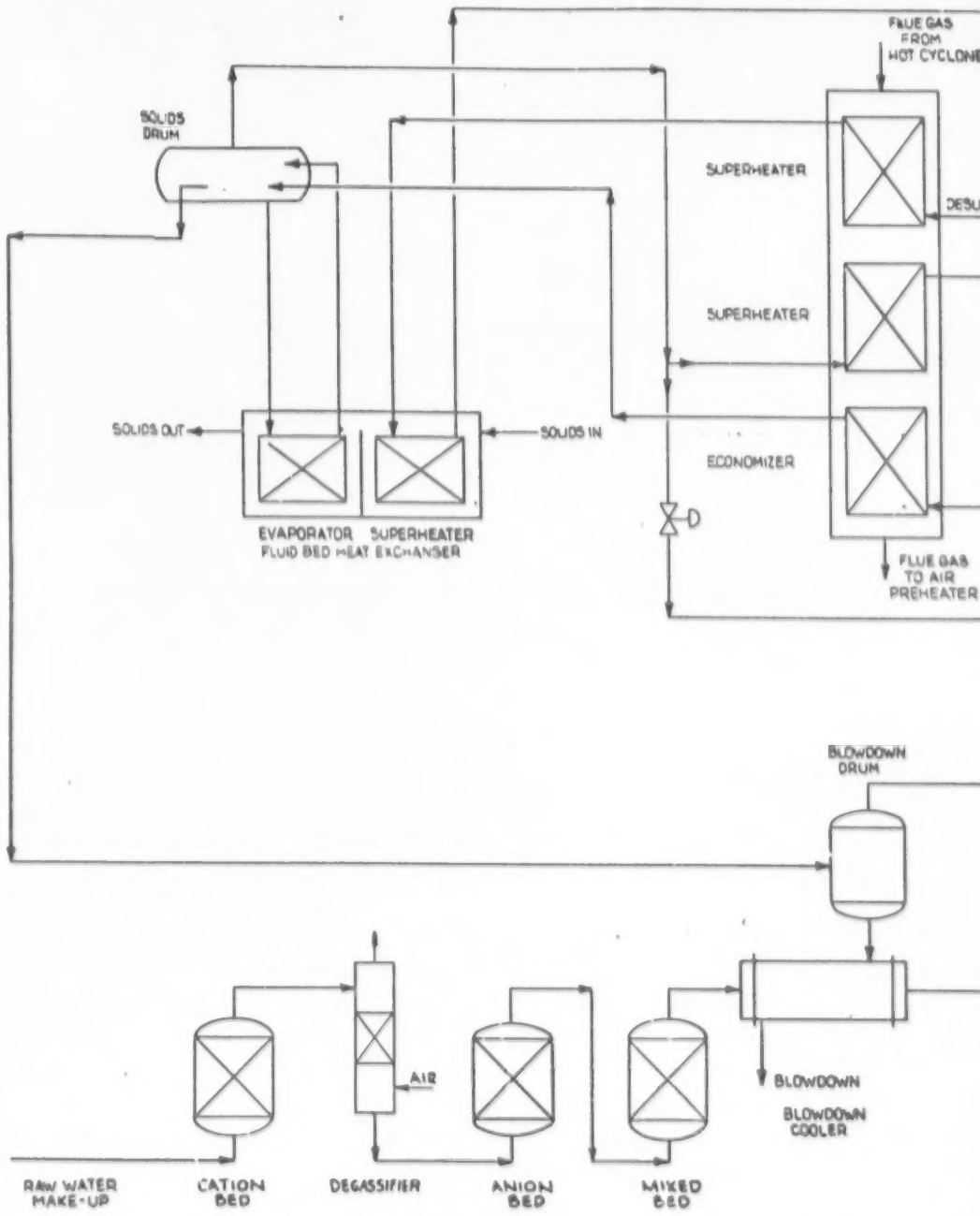
LURGI CORPORATION
RIVER EDGE, NEW JERSEY.

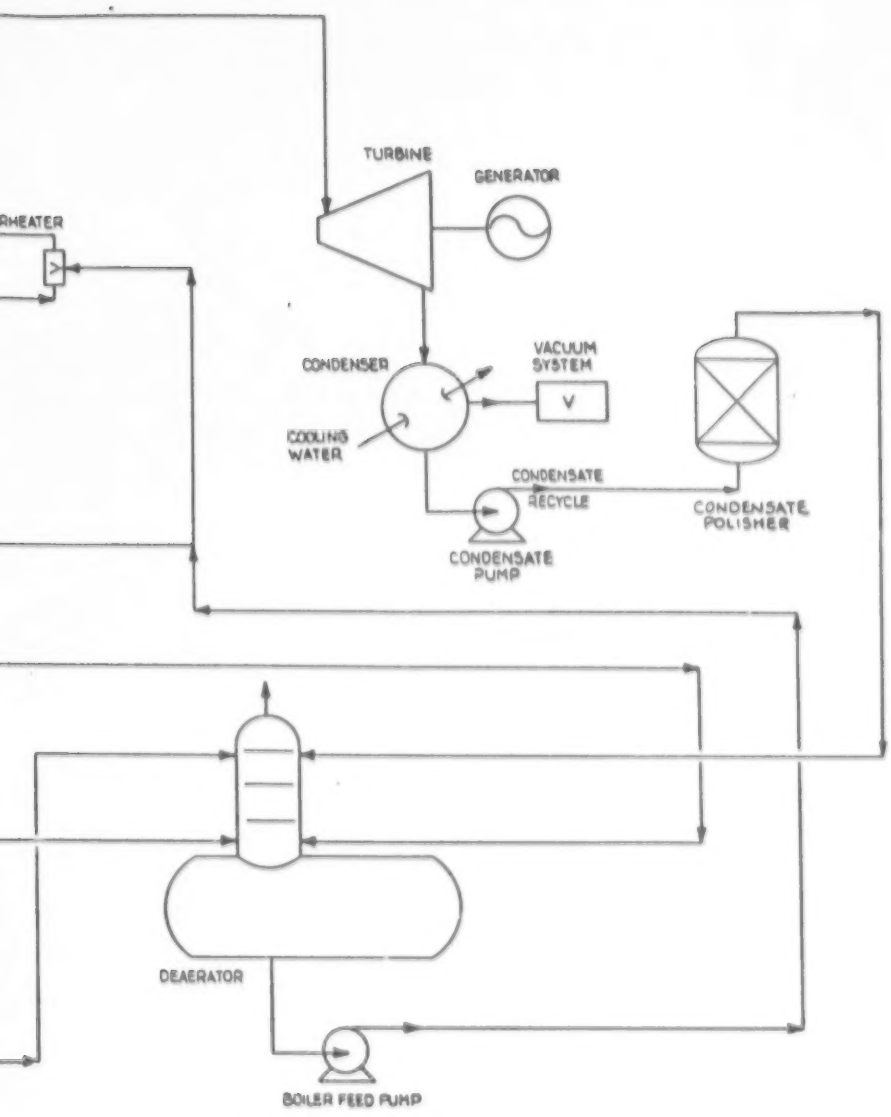
CLIENT: LUSCAR
PROJECT: WASTE COAL UTILIZATION STUDY
LOCATION: COAL VALLEY, ALBERTA
PROJECT NO: 62504

DRAWING TITLE

PROCESS FLOW DIAGRAM
CFB COMBUSTOR FOR
A 30 MW PLANT

SCALE	DRAWING NUMBER	REV.
~NS	P-62504-1	8


FLUE GAS
FROM
HOT CYCLONE
SOLIDS
DRUM
SUPERHEATER
SUPERHEATER
SOLIDS OUT
SOLIDS IN
ECONOMIZER
EVAPORATOR
FLUID BED HEAT EXCHANGER
SUPERHEATER
FLUE GAS
TO AIR
PREHEATER
BLOWDOWN
DRUM
AIR
BLOWDOWN
BLOWDOWN
COOLER
RAW WATER
MAKE-UP
CATION
BED
DEGASSIFIER
ANION
BED
MIXED
BED



REV	DATE	DESCRIPTION	DWN	APPD
2	11/94	UPDATED	JF	HB
1	7/94	PRELIMINARY	EM	

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LURGI CORPORATION
RIVER EDGE, NEW JERSEY.

CLIENT: LUSCAR
PROJECT: WASTE COAL UTILIZATION STUDY
LOCATION: COAL VALLEY, ALBERTA
PROJECT NO: 62504

DRAWING TITLE

PROCESS FLOW DIAGRAM STEAM AND POWER GENERATION FOR 30 MW PLANT

SCALE	DRAWING NUMBER	REV.
~	P- 62504 - 3	B